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CHESAPEAKE UTILITIES

2009 SEP -4 PM 2:51

PSC DOCKET
DELAWARE

NO. 07-398 F

September 4, 2009

Ms. Katie Rochester, Acting Secretary
Delaware Public Service Commission
861 Silver Lake Boulevard
Cannon Building, Suite 100
Dover, Delaware 19904

RE: Chesapeake Utilities Corporation - Gas Sales Service Rates to be effective November 1, 2009

Dear Ms. Rochester:

Enclosed for filing are an original and ten (10) copies of Chesapeake Utilities Corporation's ("Chesapeake") application for a proposed change in its Gas Sales Service Rates ("GSR") to be effective for service rendered on and after November 1, 2009.

Pursuant to the provisions of Chesapeake's GSR tariff clause, Chesapeake submits the following Gas Sales Service Rates to be effective for service rendered on and after November 1, 2009: $0.956 per Ccf for customers served under rate schedules RS-1, RS-2, GS, MVS and LVS, $0.645 per Ccf for customers served under rate schedules GLR and GLO, $0.797 per Ccf for customers served under rate schedule HLFS. The Company also submits the following balancing rates to be effective for service rendered on and after November 1, 2009: $0.056 per Ccf for transportation customers served under rate schedule LVS, and $0.007 per Ccf for transportation customers served under rate schedule HLFS, and $0.002 per Ccf for transportation customers served under the rate schedule ITS.

As compared to the rates that were in effect on February 1, 2009 an average RS-2 customer using 700 Ccf per year will experience an annual decrease of approximately 16% or $17 per month. During the winter heating season, a typical customer on Chesapeake's system using 110 Ccf per month will experience a decrease of approximately 18% or $32 per winter month. An RS-2 customer using 120 Ccf per month will experience a decrease of approximately 18% or $34 per winter month.

Chesapeake Utilities Corporation
350 South Queen Street • Dover, Delaware 19904 • 302.734.6797 • 302.734.6010 / fax
www.chpkgas.com

As compared to the rates that were in effect on November 1, 2008 an average RS-2 customer using 700 Ccf per year will experience an annual decrease of approximately 25% or $30 per month. During the winter heating season, a typical customer on Chesapeake's system using 110 Ccf per month will experience a decrease of approximately 28% or $56 per winter month. An RS-2 customer using 120 Ccf per month will experience a decrease of approximately 28% or $61 per winter month.

The basis and reasons for the proposed changes are discussed and explained in the testimony and schedules accompanying the enclosed application.

Also, enclosed is the Delaware Public Service Commission's "Filing Cover Sheet" along with the application fee of $100.00.

Should you have any questions with regard to this submission, please contact me at 302.736.7818.

Sincerely,

Jennifer A. Clausius

Jennifer A. Clausius
Manager of Pricing and Regulation

Enclosures

CC: William A. Denman, Esquire
G. Arthur Padmore
Janis Dillard (w/o enclosure)
Funmi I. Jegede (w/o enclosure)

For PSC Use Only:
Docket No. ________
Filing Date: ________
Reviewer: ________
Given to: ________

DELAWARE PUBLIC SERVICE COMMISSION
FILING COVER SHEET

1. NAME OF APPLICANT: Chesapeake Utilities Corporation
2. TYPE OF FILING:
   - RATE CHANGE __
   - FUEL ADJUSTMENT X
   - ADMINISTRATIVE __
   - CPCN __
   - NEW SERVICE OFFERING __
   - OTHER __

IF A TELECOMMUNICATIONS FILING, WHAT TYPE OF SERVICE IS IMPACTED? (PLEASE CHECK)

BASIC___ COMPETITIVE___ DISCRETIONARY

3. PROPOSED EFFECTIVE DATE: 11/01/2009

   IS EXPEDITED TREATMENT REQUESTED? YES __ NO X

4. SHORT SYNOPSIS OF FILING: Chesapeake Utilities Corporation proposes to change its GSR charges to be effective with service rendered on and after November 1, 2009.

5. DOES THIS FILING RELATE TO PENDING DOCKETS? YES__ NO X__

   IF SO, PLEASE LIST DOCKET(S) NO(S):

6. IS PUBLIC NOTICE REQUIRED? YES X__ NO

   IF YES, PLEASE ATTACH COPY OF PROPOSED PUBLIC NOTICE.

7. APPLICANT'S CONTACT PERSON:
   - (NAME) Jennifer A. Clausius
   - (TITLE) Manager of Pricing and Regulation
   - (TELE. NO.) 302.736.7818
   - (FAX NO.) 302.734.6011

8. DID YOU PROVIDE A COMPLETE COPY OF THE FILING TO THE PUBLIC ADVOCATE?

   YES X NO ___ IF SO, WHEN? September 4, 2009

9. FILING FEE ENCLOSED: $100.00 (AMOUNT)

NOTE: House Bill 681, enacted into law 7/13/98, authorizes the Commission to recover the cost of time spent by in-house staff to process all filings initiated after the date of enactment. You may be required to reimburse the Commission for staff time.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF CHESAPEAKE UTILITIES CORPORATION FOR APPROVAL OF A CHANGE IN ITS GAS SALES SERVICE RATES ("GSR") TO BE EFFECTIVE NOVEMBER 1, 2009	)))))	P.S.C. DOCKET NO. 09-

CERTIFICATE OF SERVICE

I, Jennifer A. Clausius, do hereby certify that on September 4, 2009, a copy of Chesapeake Utilities Corporation – Delaware Division's application for a proposed change in its Gas Sales Service Rates to be effective for service rendered on and after November 1, 2009 was issued to the following persons in the manner indicated:

VIA HAND DELIVERY W/O ENCLOSURE
FUNMI I. JEGEDE
DELAWARE PUBLIC SERVICE COMMISSION
861 SILVER LAKE BLVD
CANNON BUILDING, SUITE 100
DOVER, DELAWARE 19904

VIA HAND DELIVERY
WILLIAM A. DENMAN, ESQUIRE
PARKOWSKI, GUERKE AND SWAYZE P.A.
116 WEST WATER STREET
P. O. BOX 598
DOVER, DELAWARE 19903

VIA OVERNIGHT DELIVERY
G. ARTHUR PADMORE, PUBLIC ADVOCATE
DIVISION OF THE PUBLIC ADVOCATE
820 N. FRENCH STEET, 4TH FLOOR
WILMINGTON, DE 19801

VIA HAND DELIVERY W/O ENCLOSURE
JANIS DILLARD
DELAWARE PUBLIC SERVICE COMMISSION
861 SILVER LAKE BLVD
CANNON BUILDING, SUITE 100
DOVER, DELAWARE 19904

Jennifer A. Clausius

Jennifer A. Clausius
Manager of Pricing and Regulation

"DRAFT"

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF CHESAPEAKE UTILITIES CORPORATION FOR APPROVAL OF A CHANGE IN ITS GAS SALES SERVICE RATES ("GSR") TO BE EFFECTIVE NOVEMBER 1, 2009 (FILED SEPTEMBER 4, 2009)	))))))	**PSC DOCKET NO. 09-**

PUBLIC NOTICE

TO: ALL NATURAL GAS CUSTOMERS OF CHESAPEAKE UTILITIES CORPORATION AND ANY OTHER INTERESTED PERSONS

Pursuant to 26 Del. C. §§303(b) and 304, Chesapeake Utilities Corporation has filed with the Delaware Public Service Commission ("the Commission") an application proposing to change its current Gas Sales Service Rates in the following manner: (1) decrease the surcharge from \$1.243 per Ccf to \$0.956 per Ccf for customers served under rate schedules RS-1, RS-2, GS, MVS and LVS; (2) decrease the surcharge from \$1.013 per Ccf to \$0.645 per Ccf for customers served under rate schedules GLR and GLO; (3) decrease the surcharge from \$1.172 per Ccf to \$0.797 per Ccf for customers served under rate schedule HLFS; (4) decrease the balancing rate from \$0.060 per Ccf to \$0.056 per Ccf for transportation customers served under rate schedule LVS; (5) decrease the balancing rate from \$0.019 per Ccf to \$0.007 per Ccf for transportation customers served under rate schedule HLFS and (6) decrease the balancing rate from \$0.004 per Ccf to \$0.002 per Ccf for transportation customers served under the rate schedule ITS.

At its meeting on ______________, the Commission determined to allow the proposed changes to take effect on November 1, 2009 on a temporary basis, subject to refund, pending public evidentiary hearings which will be conducted upon due public notice. The Commission's actions on this matter will be based upon the evidence presented at such hearing(s).

Any person or group who wishes to formally participate as a party to this Docket (PSC Docket No. 09-_____), must, in accordance with Rule 11 of the Commission's Rules of Practice, petition the Commission for and be granted leave to intervene in the proceedings in this docket. To be timely, all such petitions must be filed with the Delaware Public Service Commission at 861 Silver Lake Boulevard, Cannon Building, Suite 100, Dover, DE 19904 on or before ______________, 2009. Petitions received thereafter will not be considered except for good cause shown.

Copies of Chesapeake's Application and the testimony and exhibits the Company has filed in this docket are available for public inspection at the Commission's office at the address set out above.

Any individual with disabilities who wishes to participate in these proceedings, or to review this tariff filing, should contact the Commission to discuss any auxiliary aids or services needed to facilitate such review or participation. Such contact may be in person, by writing, telephonically, by use of the Telecommunications Relay Service, or otherwise. Persons with questions concerning this matter may contact the Commission at its toll-free number (for calls made within Delaware) (800) 282-8574, or by regular telephone at (302) 736-7500.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF	**)**	
CHESAPEAKE UTILITIES CORPORATION	**)**	
FOR APPROVAL OF A CHANGE IN ITS	**)**	**P.S.C. DOCKET NO.**
GAS SALES SERVICE RATES ("GSR")	**)**	
TO BE EFFECTIVE NOVEMBER 1, 2009	**)**	

Chesapeake Utilities Corporation (hereinafter sometimes called "Applicant") pursuant to 26 Del. C. 303(b) and 304, makes the following application for approval by the Commission of a change in its Gas Sales Service Rates ("GSR") and balancing rates to be effective for service rendered on and after November 1, 2009:

1. Applicant is Chesapeake Utilities Corporation, 909 Silver Lake Boulevard, Dover, Delaware 19904. All communications should be addressed to the Applicant at the following address, Attention: Jennifer A. Clausius, Manager of Pricing and Regulation, 350 South Queen Street, P.O. Box 1769, Dover, Delaware 19903 or at the following e-mail address: jclausius@chpk.com. The respective phone number and fax number are 302.736.7818 and 302.734.6011. All communications should also be addressed to Michael D. Cassel, Regulatory Analyst III, 350 South Queen Street, P.O. Box 1769, Dover, Delaware 19903 or at the following e-mail address: mcassel@chpk.com. The respective phone number and fax number are 302.734.6797, extension 6747 and 302.734.6011.

2. Counsel for the Applicant is William A. Denman, Esquire, Parkowski, Guerke & Swayze P.A., 116 West Water Street, P.O. Box 598, Dover, Delaware 19903. Correspondence and other communications concerning this application should be directed to counsel at the foregoing address, or at the following e-mail address: wdenman@pgslegal.com. The respective phone number and fax number are 302.678.3262 and 302.678.9415.

3. Pursuant to the provisions of Applicant's Gas Sales Service Rate tariff clause, Applicant requests permission to decrease Applicant's current Gas Sales Service Rates from positive surcharges of $1.243 per Ccf for customers served under rate schedules RS-1, RS-2, GS, MVS and LVS, $1.013 per Ccf for customers served under rate schedules GLR and GLO, $1.172 per Ccf for customers served under rate schedule HLFS, to positive surcharges of $0.956 per Ccf, $0.645 per Ccf and $0.797 per Ccf respectively, said changes to be effective for service rendered on and after November 1, 2009 and thereafter until changed by further order of the Delaware Public Service Commission.

4. Applicant also requests permission to decrease Applicant's firm balancing rate for transportation customers served under Rate Schedule Large Volume Service ("LVS") from $0.060 per Ccf to $0.056 per Ccf, decrease Applicant's firm balancing rate for transportation customers served under Rate Schedule "HLFS" from $0.019 per Ccf to $0.007 per Ccf, and decrease Applicant's interruptible balancing rate for transportation customers served under Rate Schedule "ITS" from $0.004 per Ccf to $0.002 per Ccf.

5. Applicant also requests approval for a waiver of the sixty (60) day notice requirement for these reduced rates to be effective for service rendered on and after November 1, 2009. Due to current business needs, the Company requested, and was granted by Commission Staff, additional time to file its Application.

6. The full calculation of the proposed Gas Sales Service Rates is set forth in Schedule A.1 and the calculation of the balancing rates is set forth in Schedule J, which are attached to this Application. The reasons and basis for the proposed changes in Applicant's present Gas Sales Service Rates and balancing rates are more fully explained by direct testimony filed herewith.

WHEREFORE, the Applicant prays as follows:

A. That the Commission file this Application and schedule it for hearing;

B. That the Commission waive the sixty (60) day notice requirement for these reduced rates so that they may be effective, subject to refund, on November 1, 2009.

C. That the Commission approve the proposed decrease in Applicant's Gas Sales Service Rates to a positive surcharge of $0.956 per Ccf for customers served under rate schedules RS-1, RS-2, GS, MVS and LVS, $0.645 per Ccf for customers served under rate schedules GLR and GLO, $0.797 per Ccf for customers served under rate schedule HLFS; and also approve the proposed decrease in Applicant's firm balancing rate for transportation customers served under rate schedule LVS to a positive surcharge of $0.056 per Ccf, approve the proposed decrease in Applicant's firm balancing rate for transportation customers served under rate schedule HLFS to a positive surcharge of $0.007 per Ccf, and approve the proposed decrease in Applicant's interruptible balancing rate for transportation customers served under rate schedule ITS to a positive surcharge of $0.002 per Ccf, all of said changes to be effective for service rendered on and after November 1, 2009.

SIGNATURES APPEAR ON THE FOLLOWING PAGE

CHESAPEAKE UTILITIES CORPORATION

BY: Jeffrey R. Tietbohl
Jeffrey R. Tietbohl
Assistant Vice President

Parkowski, Guerke & Swayze P.A.

BY: William A Denman
William A. Denman
116 West Water Street
Dover, DE 19903
Attorney for Applicant

DATED: September 4, 2009

DATED: SEPTEMBER 4, 2009

STATE OF DELAWARE)
)
COUNTY OF KENT)

BE IT REMEMBERED that on this 4th day of September 2009 personally appeared before me, a notary public for the State and County aforesaid, Jeffrey R. Tietbohl, who being by me duly sworn, did depose and say that he is Assistant Vice President for Chesapeake Utilities Corporation, a Delaware corporation and insofar as the Application of Chesapeake Utilities Corporation states facts, said facts are true and correct, and insofar as those facts are not within his personal knowledge, he believes them to be true, and that the schedules accompanying this application and attached hereto are true and correct copies of the originals of the aforesaid schedules, and that he has executed this Application on behalf of the Company.

Jeffrey R. Tietbohl

SWORN TO AND SUBSCRIBED before me the day and year above written.

Rebecca K. Little
Notary Public
My Commission Expires: 8/7/2010

REBECCA K. LITTLE
COM. EXP.
NOTARY
PUBLIC
8-7-2010
STATE OF DELAWARE

Chesapeake Utilities Corporation
Delaware Division
Development of Gas Sales Service Rates Effective November 1, 2009

Based on Total Firm Gas Costs Recoverable through GSR effective November 1, 2009

Description	Allocator	Total System Costs	Volume (Ccf)	Cost / Ccf
Fixed Gas Costs	Peak Day Capacity Entitlements	$15,820,014	621,266	$25.46
Variable Gas Costs	Annual Volume	$25,990,040	45,209,210	$0.575
Total Firm Gas Costs	Annual Volume	$41,810,055	45,209,210	$0.925

Development of High Load Factor Service Rates per CCF (74% Load Factor)

Description		Peak Day Cap. Method	System Average Cost	HLFS Average Rate
Demand Rate	($25.46 / 270)	$0.094		
Commodity Rate		$0.575		
Total Gas Sales Service Rate		$0.669	$0.925	$0.797

Total High Load Factor and Seasonal Firm Dollars

Projected Sales	Rate	Total Cost
11,467,640	$0.797	$9,139,709

Development of Gas Lighting Rate per CCF (100% Load Factor)

Description		Peak Day Cap. Method
Demand Rate	($25.46 / 365)	$0.070
Commodity Rate		$0.575
Total Gas Sales Service Rate		$0.645

Total Gas Lighting Dollars

Projected Sales	Rate	Total Cost
1,460	$0.645	$942

Development of RS1, RS2, GS, MVS, and LVS Rate per CCF

Description	Firm Gas Cost	Volume (CCF)	Rate per CCF	Margin Sharing Rate per CCF	Final Rate per CCF
Total System Gas Cost	$41,810,055	45,209,210			
Less : Allocated to HLFS	$9,139,709	11,467,640			
Less : Allocated to GL	$942	1,460			
Total Remaining System	$32,669,404	33,740,110	$0.968	($0.012)	$0.956

Chesapeake Utilities Corporation
Delaware Division
Transportation Balancing Services
Development of Firm Balancing Service Rate
Large Volume Service

Fixed Gas Supply Cost	Annual Load Factor	Average Daily Load	Cost Per Gas Supply Entitlement	Average Cost per DT	Average Cost 45.25% Design Day
@ Load Factor of	10%	37	$120.4241	$3.2547	$1.4728
@ Load Factor of	20%	73	$120.4241	$1.6496	$0.7464
@ Load Factor of	30%	110	$120.4241	$1.0948	$0.4954
@ Load Factor of	40%	146	$120.4241	$0.8248	$0.3732
@ Load Factor of	50%	183	$120.4241	$0.6581	$0.2978
@ Load Factor of	60%	219	$120.4241	$0.5499	$0.2488
@ Load Factor of	70%	256	$120.4241	$0.4704	$0.2129
@ Load Factor of	80%	292	$120.4241	$0.4124	$0.1866
@ Load Factor of	90%	329	$120.4241	$0.3660	$0.1656
@ Load Factor of	100%	365	$120.4241	$0.3299	$0.1493
Del. Div. Weighted Average	**28.03%**	**102**	**$120.4241**	**$1.1806**	**$0.5342**

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			**$0.0147**	**24.91%**	**$0.0037**

Development of Firm Balancing Service Rate		
Fixed Capacity Rate per DT	**$0.5342**	
Variable Commodity Rate per DT	**$0.0037**	
Total Firm Balancing Service Rate per DT	**$0.5379**	
Total Firm Balancing Service Rate per Mcf	**$0.5567**	
Total Firm Balancing Service Rate per Ccf	**$0.056**	

Chesapeake Utilities Corporation
Delaware Division
Transportation Balancing Services
Development of Firm Balancing Service Rate
High Load Factor Service

Fixed Gas Supply Cost	Annual Load Factor	Average Daily Load	Cost Per Gas Supply Entitlement	Average Cost per DT	Average Cost 16.05% Design Day
@ Load Factor of	10%	37	$120.4241	$3.2547	$0.5224
@ Load Factor of	20%	73	$120.4241	$1.6496	$0.2648
@ Load Factor of	30%	110	$120.4241	$1.0948	$0.1757
@ Load Factor of	40%	146	$120.4241	$0.8248	$0.1324
@ Load Factor of	50%	183	$120.4241	$0.6581	$0.1056
@ Load Factor of	60%	219	$120.4241	$0.5499	$0.0883
@ Load Factor of	70%	256	$120.4241	$0.4704	$0.0755
@ Load Factor of	80%	292	$120.4241	$0.4124	$0.0662
@ Load Factor of	90%	329	$120.4241	$0.3660	$0.0587
@ Load Factor of	100%	365	$120.4241	$0.3299	$0.0529
Del. Div. Weighted Average	**74.16%**	**271**	**$120.4241**	**$0.4444**	**$0.0713**

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			**$0.0147**	3.42%	**$0.0005**

Development of Firm Balancing Service Rate		
Fixed Capacity Rate per DT	**$0.0713**	
Variable Commodity Rate per DT	**$0.0005**	
Total Firm Balancing Service Rate per DT	**$0.0718**	
Total Firm Balancing Service Rate per Mcf	**$0.0743**	
Total Firm Balancing Service Rate per Ccf	**$0.007**	

Chesapeake Utilities Corporation
Delaware Division
Transportation Balancing Services
Development of Interruptible Balancing Service Rate
Interruptible Transportation Service

Fixed Gas Supply Cost	Annual Load Factor	Average Daily Load	Cost Per Gas Supply Entitlement	Average Cost per DT	Average Cost @ Use of 6.58%
@ Load Factor of	10%	37	$120.4241	$3.2547	
@ Load Factor of	20%	73	$120.4241	$1.6496	
@ Load Factor of	30%	110	$120.4241	$1.0948	
@ Load Factor of	40%	146	$120.4241	$0.8248	
@ Load Factor of	50%	183	$120.4241	$0.6581	
@ Load Factor of	60%	219	$120.4241	$0.5499	
@ Load Factor of	70%	256	$120.4241	$0.4704	
@ Load Factor of	80%	292	$120.4241	$0.4124	
@ Load Factor of	90%	329	$120.4241	$0.3660	
@ Load Factor of	100%	365	$120.4241	$0.3299	
Interruptible @ 100% LFR	**100.00%**	**365**	**$120.4241**	**$0.3299**	**$0.0217**

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			**$0.0147**	6.58%	**$0.0010**

Development of Interruptible Balancing Service Rate		
Fixed Capacity Rate per DT	**$0.0217**	
Variable Commodity Rate per DT	**$0.0010**	
Total Balancing Service Rate per DT	**$0.0227**	
Total Balancing Service Rate per Mcf	**$0.0235**	
Total Balancing Service Rate per Ccf	**$0.002**	

RATE SCHEDULE "LVS"

LARGE VOLUME SERVICE
(Continued)

TRANSPORTATION AND BALANCING SERVICE

Transportation service is available to commercial and industrial customers with annual consumption through one or more contiguous meters in a specific geographic location equal to, or greater than, 30,000 Ccf per year that choose to have their own gas transported through the Company's distribution system. Customers purchasing natural gas from a supplier, other than the Company, must have the natural gas delivered to the Company's city gate in accordance with the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service rate applied to all gas consumption.

Firm Balancing Service Rate: $0.056 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the customer is exempt from such tax.

PAYMENT TERMS

Bills are due within ten (10) days of their date.

MINIMUM BILL

The minimum monthly bill under this rate schedule is the customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this rate schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the customer in one location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles.

RATE SCHEDULE "HLFS"

HIGH LOAD FACTOR SERVICE
(Continued)

TRANSPORTATION AND BALANCING SERVICE

Transportation service is available to commercial and industrial customers with annual consumption through one or more contiguous meters in a specific geographic location equal to, or greater than, 30,000 Ccf per year that choose to have their own gas transported through the Company's distribution system. Customers purchasing natural gas from a supplier, other than the Company, must have the natural gas delivered to the Company's city gate in accordance with the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the customer is subject to the following Firm Balancing Service rate applied to all gas consumption

Firm Balancing Service Rate: $0.007 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the customer is exempt from such tax.

PAYMENT TERMS

Bills are due within ten (10) days of their date.

MINIMUM BILL

The minimum monthly bill under this rate schedule is the customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this rate is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the customer in one location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles.

Issue Date: September 4, 2009
Effective Date: For Service Rendered on and after November 1, 2009
Authorization:

RATE SCHEDULE "ITS"

INTERRUPTIBLE TRANSPORTATION SERVICE

AVAILABILITY

This rate schedule is available to any non-residential customer with annual consumption of at least 100,000 Ccf with facilities in operating condition capable of utilizing an alternative fuel due to the fact gas service provided is subject to complete interruption at any time during the year at the Company's option. The definition of an alternative fuel under this rate schedule shall be propane, fuel oil, or electricity. When applying for service under this Rate Schedule, the Customer is required to provide the Company, in writing, with the type and specific grade of alternative fuel utilized by the Customer. The Customer shall submit, within 30 days of any change in operations, written notification when such change affects its alternate fuel capability. Customer must also purchase all of its gas from or through a supplier of natural gas

DELIVERY SERVICE RATE

Customer charge: $935.00 per month

The rate per Ccf of consumption shall be determined on an individual customer basis according to the nature of the interruptible service to be provided. This rate can be adjusted upon one (1) days notice to the Customer.

TRANSPORTATION AND BALANCING SERVICE

Customers must have the natural gas delivered to the Company's city gate in accordance with the Transportation and Balancing Rider General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rate, the Customer is subject to the following Interruptible Balancing Service rate applied to all gas consumption.

Interruptible Balancing Service Rate: $.002 per Ccf of gas consumed

RATE SCHEDULE "GSR"

GAS SALES SERVICE RATES

FIRM SALES RATE SCHEDULES

The Gas Sales Service Rates applicable to the respective firm rate schedule, as listed below, will be applied to all customers served on that schedule based on a volumetric charge per Ccf (100 cubic feet). The Gas Sales Service Rates only apply to the respective firm rate schedules listed below and do not apply to the Interruptible Transportation Service, Transportation Service, Negotiated Contract Rate, and Interruptible Best Efforts Sales Service. The Gas Sales Service Rates will be calculated to the nearest tenth of a cent (.1¢).

The following lists the applicable Gas Sales Service Rates for the respective firm rate schedules as defined in this tariff:

RATE SCHEDULE	GAS SALES SERVICE RATES
RS, GS, MVS, LVS	$0.956 per Ccf
HLFS, SFS	$0.645 per Ccf
GLR, GLO, GCR, GCO	$0.797 per Ccf

These rates are subject to change based on actual and estimated gas costs. The Company will file with the Commission a copy of these Gas Sales Service Rates at least sixty (60) days prior to the regularly scheduled adjustment date, which shall be each November 1.

The November 1 rates will be based on a projected twelve-month period of November through October (projected period). The rates computed under this rate schedule shall remain in effect for the projected period provided the latest estimated over collection does not exceed 4½% or the latest estimated under collection does not exceed 6% of the actual firm gas costs incurred to date along with the Company's latest firm gas cost estimates for the remainder of the over/under collection period (over/under period). The twelve-month period used for the calculation of the over/under period will be based on the actual nine months ended July 31 of each year and the projected three months ended October 31 of each year. If it appears that the use of these rates for the twelve-month over/under period will result in an over or under collection exceeding these limits, the Company shall apply to the Commission for revised rates to be effective until the next annual adjustment in the rates.

Issue Date: September 4, 2009
Effective Date: For Service Rendered on and after November 1, 2009
Authorization:

RATE SCHEDULE "GSR"

GAS SALES SERVICE RATES
(Continued)

OVERALL METHODOLOGY (Continued)

A Demand Rate will be determined by dividing the total firm fixed cost components by the firm peak day capacity requirements. A Commodity Rate will be determined by dividing the total firm commodity cost components by total firm consumption for the respective determination period.

ALLOCATION TO RESPECTIVE FIRM RATE SCHEDULES

Rate Schedule HLFS - High Load Factor Service will be charged a single gas cost rate per Ccf based on the combination of a weighted average Demand and Commodity Rate developed on an overall seventy-four percent (74%) load factor for the customer class with the overall system weighted average gas cost rate. The purchased gas costs will be allocated to this Rate Schedule based on its annual consumption for the projected period.

Rate Schedule GLO, GLR - The Gas Lighting Services will be charged the weighted average Demand and Commodity Rates through a single gas cost rate per Ccf based on a 100% load factor. The purchased gas costs will be allocated to this Rate Schedule based on its annual consumption for the projected period.

Rate Schedule RS-1, RS-2, GS, MVS, LVS - These rate schedules will be assigned the remaining firm purchased gas costs after the firm purchased gas costs have been allocated to the above mentioned Rate Schedules less the portion of any shared margins resulting from capacity release, or off-system sales. These Rate Schedules will be charged a single gas cost rate per Ccf. This rate will reflect the sum of the projected demand and commodity costs for these classes divided by the sum of their annual consumption for the projected period.

MARGIN SHARING

Margins as used herein for off system sales means revenues less: (a) associated gas costs and (b) any applicable taxes based on gross receipts. Margins as used herein for capacity release means revenues less any applicable taxes based on gross receipts. As used in this tariff, the term "Shared Margins" means off system sales margins, and upstream capacity release margins.

RATE SCHEDULE "GSR"

GAS SALES SERVICE RATES
(Continued)

MARGIN SHARING (Continued)

During the over/under period, the Company shall retain twenty percent (20%) and the firm customers, as described above, will receive eighty percent (80%) of all Shared Margins resulting from off-system sales. Additionally, during the over/under period, the Company shall retain ten percent (10%) and the firm customers, as described above, will receive ninety percent (90%) of all Shared Margins resulting from upstream capacity release transactions.

UNACCOUNTED FOR GAS INCENTIVE MECHANISM

The Unaccounted For Gas Incentive Mechanism was originally approved by the Commission on an experimental basis for the following three consecutive twelve month ending periods: August 31, 1993, 1994 and 1995. The Commission reviewed the Incentive Mechanism and determined it should be continued beyond the initial three year period by Order No. 4189 in PSC Docket No. 95-206F.

DEFINITIONS

The terms utilized in the Unaccounted For Gas Incentive Mechanism shall have the following meanings:

1. Unaccounted For Gas shall be defined as the difference between total gas sales, billed and unbilled, and total gas send-out, exclusive of company use gas and pressure compensated gas volumes.

2. The Unaccounted For Gas Target (UFG-T) shall be 3.20 percent of total gas sendout or total gas requirements.

3. The Dead Band shall mean +/- 0.5% points around the 3.20% UFG-T. Unaccounted For Gas volumes which are within 2.70% to 3.70% of total gas sendout will be considered to be within the "dead band". Unaccounted For Gas volumes within the dead band will be regarded as meeting the objectives of this mechanism.

RATE SCHEDULE "LVS"

LARGE VOLUME SERVICE
(Continued)

TRANSPORTATION AND BALANCING SERVICE

Transportation service is available to commercial and industrial customers with annual consumption through one or more contiguous meters in a specific geographic location equal to, or greater than, 30,000 Ccf per year that choose to have their own gas transported through the Company's distribution system. Customers purchasing natural gas from a supplier, other than the Company, must have the natural gas delivered to the Company's city gate in accordance with the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the Customer is subject to the following Firm Balancing Service rate applied to all gas consumption.

Firm Balancing Service Rate: $0.0~~60~~56 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the customer is exempt from such tax.

PAYMENT TERMS

Bills are due within ten (10) days of their date.

MINIMUM BILL

The minimum monthly bill under this rate schedule is the customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this rate schedule is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the customer in one location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles.

Issue Date: **September ~~2~~4, 200~~8~~9**
Effective Date: **For Service Rendered on and after November 1, 200~~8~~9**
Authorization:

RATE SCHEDULE "HLFS"

HIGH LOAD FACTOR SERVICE
(Continued)

TRANSPORTATION AND BALANCING SERVICE

Transportation service is available to commercial and industrial customers with annual consumption through one or more contiguous meters in a specific geographic location equal to, or greater than, 30,000 Ccf per year that choose to have their own gas transported through the Company's distribution system. Customers purchasing natural gas from a supplier, other than the Company, must have the natural gas delivered to the Company's city gate in accordance with the Transportation and Balancing General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rates, the customer is subject to the following Firm Balancing Service rate applied to all gas consumption

Firm Balancing Service Rate: $0.0~~19~~07 per Ccf of gas consumed

PUBLIC UTILITIES TAX

The Delivery Service, Gas Sales Service, Firm Balancing Service, and any other applicable rates or charges are subject to the Delaware Public Utilities Tax unless the customer is exempt from such tax.

PAYMENT TERMS

Bills are due within ten (10) days of their date.

MINIMUM BILL

The minimum monthly bill under this rate schedule is the customer charge.

SPECIAL TERMS AND CONDITIONS OF SERVICE

(1) Service under this rate is subject to the standard terms and conditions of service as in effect from time to time under authority of the Public Service Commission of Delaware. It is also subject to the limitations stated under the "Availability" clause above.

(2) Natural gas purchased hereunder is for the use of the customer in one location only and is not to be shared or sold to others except for retail sale as a fuel to natural gas vehicles.

P.S.C. Del. No. 4
Chesapeake Utilities Corporation
Delaware Division

~~Fourth~~Fifth Revised Sheet No. 40

RATE SCHEDULE "ITS"

INTERRUPTIBLE TRANSPORTATION SERVICE

AVAILABILITY

This rate schedule is available to any non-residential customer with annual consumption of at least 100,000 Ccf with facilities in operating condition capable of utilizing an alternative fuel due to the fact gas service provided is subject to complete interruption at any time during the year at the Company's option. The definition of an alternative fuel under this rate schedule shall be propane, fuel oil, or electricity. When applying for service under this Rate Schedule, the Customer is required to provide the Company, in writing, with the type and specific grade of alternative fuel utilized by the Customer. The Customer shall submit, within 30 days of any change in operations, written notification when such change affects its alternate fuel capability. Customer must also purchase all of its gas from or through a supplier of natural gas

DELIVERY SERVICE RATE

Customer charge: $935.00 per month

The rate per Ccf of consumption shall be determined on an individual customer basis according to the nature of the interruptible service to be provided. This rate can be adjusted upon one (1) days notice to the Customer.

TRANSPORTATION AND BALANCING SERVICE

Customers must have the natural gas delivered to the Company's city gate in accordance with the Transportation and Balancing Rider General Terms and Conditions provided on Sheet No. 43. In addition to the above Delivery Service rate, the Customer is subject to the following Interruptible Balancing Service rate applied to all gas consumption.

Interruptible Balancing Service Rate: $.0042 per Ccf of gas consumed

Issue Date: September ~~2~~4, 200~~8~~9
Effective Date: For Service Rendered on and after November 1, 200~~8~~9
Authorization:

RATE SCHEDULE "GSR"

GAS SALES SERVICE RATES

FIRM SALES RATE SCHEDULES

The Gas Sales Service Rates applicable to the respective firm rate schedule, as listed below, will be applied to all customers served on that schedule based on a volumetric charge per Ccf (100 cubic feet). The Gas Sales Service Rates only apply to the respective firm rate schedules listed below and do not apply to the Interruptible Transportation Service, Transportation Service, Negotiated Contract Rate, and Interruptible Best Efforts Sales Service. The Gas Sales Service Rates will be calculated to the nearest tenth of a cent (.1¢).

The following lists the applicable Gas Sales Service Rates for the respective firm rate schedules as defined in this tariff:

RATE SCHEDULE	GAS SALES SERVICE RATES
RS, GS, MVS, LVS	$~~1.243~~0.956 per Ccf
HLFS, SFS	$~~1.172~~0.645 per Ccf
GLR, GLO, GCR, GCO	$~~1.013~~0.797 per Ccf

These rates are subject to change based on actual and estimated gas costs. The Company will file with the Commission a copy of these Gas Sales Service Rates at least sixty (60) days prior to the regularly scheduled adjustment date, which shall be each November 1.

The November 1 rates will be based on a projected twelve-month period of November through October (projected period). The rates computed under this rate schedule shall remain in effect for the projected period provided the latest estimated over collection does not exceed 4½% or the latest estimated under collection does not exceed 6% of the actual firm gas costs incurred to date along with the Company's latest firm gas cost estimates for the remainder of the over/under collection period (over/under period). The twelve-month period used for the calculation of the over/under period will be based on the actual nine months ended July 31 of each year and the projected three months ended October 31 of each year. If it appears that the use of these rates for the twelve-month over/under period will result in an over or under collection exceeding these limits, the Company shall apply to the Commission for revised rates to be effective until the next annual adjustment in the rates.

Issue Date: ~~January 8, 2009~~September 4, 2009
Effective Date: For Service Rendered on and after ~~February 1~~November 1, 2009
Authorization:

RATE SCHEDULE "GSR"

GAS SALES SERVICE RATES
(Continued)

OVERALL METHODOLOGY (Continued)

A Demand Rate will be determined by dividing the total firm fixed cost components by the firm peak day capacity requirements. A Commodity Rate will be determined by dividing the total firm commodity cost components by total firm consumption for the respective determination period.

ALLOCATION TO RESPECTIVE FIRM RATE SCHEDULES

Rate Schedule HLFS - High Load Factor Service will be charged a single gas cost rate per Ccf based on the combination of a weighted average Demand and Commodity Rate developed on an overall seventy~~sixty-~~four~~five~~ percent (~~5~~74%) load factor for the customer class with the overall system weighted average gas cost rate. The purchased gas costs will be allocated to this Rate Schedule based on its annual consumption for the projected period.

Rate Schedule GLO, GLR - The Gas Lighting Services will be charged the weighted average Demand and Commodity Rates through a single gas cost rate per Ccf based on a 100% load factor. The purchased gas costs will be allocated to this Rate Schedule based on its annual consumption for the projected period.

Rate Schedule RS-1, RS-2, GS, MVS, LVS - These rate schedules will be assigned the remaining firm purchased gas costs after the firm purchased gas costs have been allocated to the above mentioned Rate Schedules less the portion of any shared margins resulting from capacity release, or off-system sales. These Rate Schedules will be charged a single gas cost rate per Ccf. This rate will reflect the sum of the projected demand and commodity costs for these classes divided by the sum of their annual consumption for the projected period.

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RATE SCHEDULE "GSR"

GAS SALES SERVICE RATES
(Continued)

MARGIN SHARING (Continued)

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TESTIMONY & SCHEDULES OF JENNIFER CLAUSIUS

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
CHESAPEAKE UTILITIES CORPORATION	)	
FOR APPROVAL OF A CHANGE IN ITS	)	P.S.C. DOCKET NO. 09-
GAS SALES SERVICE RATES ("GSR")	)	
TO BE EFFECTIVE NOVEMBER 1, 2009	)	

DIRECT TESTIMONY OF JENNIFER A. CLAUSIUS

<u>On Behalf of Chesapeake Utilities Corporation</u>

<u>Delaware Division</u>

Submitted for filing: September 4, 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Jennifer A. Clausius and I am the Manager of Pricing and Regulation with Chesapeake Utilities Corporation ("Chesapeake" or the "Company"). My business address is 350 S. Queen Street, Dover, Delaware 19904.

Q. DESCRIBE BRIEFLY YOUR EDUCATION AND RELEVANT PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science Degree in Finance from the Pennsylvania State University in University Park, Pennsylvania in 1994. I received a Masters of Business Administration Degree from Wilmington College in Wilmington, Delaware in 2003. I was hired by Chesapeake as a Rate Analyst in February 2001 and promoted to Rate Analyst II in October 2002. As a Rate Analyst, I was primarily involved in the areas of gas cost recovery for the Delaware and Maryland natural gas distribution companies, environmental cost recovery, rate of return analysis, and base rate proceedings. Additionally, I completed cost of service studies and performed economic analysis related to capital expenditure projects. I was promoted to Manager of Pricing and Regulation in August 2005, a position in which I have direct supervision and oversight of the pricing and regulatory activities for Chesapeake's Delaware and Maryland Divisions. In late 2007 I assumed responsibility for the gas supply activities for

Chesapeake's Delaware and Maryland Divisions as well. Prior to joining Chesapeake, I was employed by Waterhouse Securities, Inc. from 1994 to 1999 as a Registered Representative and then as Assistant Branch Manager. In these positions I held a Series 7 and Series 8 registration with the National Association of Securities Dealers ("NASD"). I was also employed by AT&T Solutions, Inc. as a Financial Architect from 1999 to 2000. In this position I worked as an integral member of a sales team, analyzing the financial profitability of potential business ventures with various large companies. From 2000 to 2001 I was employed by Hospital Billing and Collection Service, Ltd., as a Financial Analyst. In this position I primarily had various revenue accounting responsibilities and was also instrumental in the development of the budget forecast.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. Yes. I have testified before the Commission during the Company's previous Gas Sales Service Rate ("GSR") proceedings, Base Rate Proceeding, Environmental Rider Rate proceedings, Franchise Fee proceeding, and its Firm Balancing and Unaccounted for Gas Cost Methodologies proceedings.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this GSR application is to support the overall calculation of the Delaware Division's three proposed GSR charges to be effective with service rendered on and after November 1, 2009 as well as ensure compliance with the gas cost provisions outlined in previous Commission Orders.

Q. ARE THERE ANY SCHEDULES INCLUDED WITH YOUR DIRECT TESTIMONY?

A. Yes. My direct testimony includes Schedules A.1, A.2, B, C.1, C.2, D.1, D.2, E, F, G, H, I, J, L, M, N.1 and N.2. These schedules have been prepared under my direct supervision.

Q. IS THE COMPANY FILING ANY OTHER DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. Chesapeake is filing the direct testimony of Michael D. Cassel, Regulatory Analyst III. Mr. Cassel will be presenting testimony explaining the mechanics of the three GSR charges and the impact on a typical residential heating customer, as well as discuss the mechanics of the Delaware Division's proposed balancing rates for transportation service under the Large Volume Service ("LVS"), High Load Factor Service ("HLFS"), and Interruptible Service ("ITS") rate schedules. Chesapeake is also filing the direct testimony of Marie E. Kozel, Gas Supply Analyst II.

Ms. Kozel will be presenting testimony regarding the Company's gas procurement and open access activities.

Q. WHAT GAS SALES SERVICE RATE LEVELS ARE YOU PROPOSING IN THIS PROCEEDING TO BE EFFECTIVE WITH SERVICE RENDERED ON AND AFTER NOVEMBER 1, 2009?

A. The Company proposes the following Gas Sales Service Rates to be effective for service rendered on and after November 1, 2009: $0.956 per Ccf for customers served under Rate Schedules RS-1, RS-2, GS, MVS and LVS, $0.645 per Ccf for customers served under Rate Schedules GLR, and GLO, and $0.797 per Ccf for customers served under Rate Schedule HLFS.

Q. WHAT PRESCRIBES THE METHODOLOGY FOR DETERMINING THE COMPANY'S GAS SALES SERVICE RATES?

A. The three Gas Sales Service Rates proposed to be effective with service rendered on and after November 1, 2009 have been developed in accordance with the approved gas cost recovery mechanism as contained in the Delaware Division's natural gas tariff, specifically Sheet Nos. 42 through 42.3. The mechanics of the calculation of the three proposed rates will be discussed in the testimony of Michael Cassel.

Q. DOES THE COMPANY'S APPLICATION CONTAIN ADDITIONAL INFORMATION IN ORDER TO COMPLY WITH PRIOR COMMISSION ORDERS?

A. Yes. The Company's filing contains support in compliance with Commission Orders issued over the past several years which I will discuss below.

Q. AS A RESULT OF COMMISSION ORDER NO. 4767 ISSUED ON APRIL 14, 1998 IN PSC DOCKET NO. 97-294F, WHAT COMMISSION STAFF RECOMMENDATIONS WAS THE COMPANY DIRECTED TO ADDRESS?

A. As a result of this Commission order, the Company was directed to comply with the following recommendations: 1) In the context of future GSR filings, keep the Commission Staff updated on the Company's gas procurement and open access activities; and 2) Perform an internal audit of the Company's margin sharing revenues in accordance with the settlement agreement in PSC Docket No. 95-73, Phase II. The margin sharing mechanism has since been revised in PSC Docket No. 01-307, Phase II and PSC Docket No. 07-186.

Q. PLEASE EXPLAIN THE COMPANY'S PROCESS IN COMPLYING WITH THE COMMISSION STAFF'S RECOMMENDATIONS AS A RESULT OF THIS ORDER.

A. As a result of the change in the margin sharing mechanism in PSC Docket No. 07-186, the Company is no longer required to share margins received from interruptible transportation customers. The Company is required to share any margins received from off-system sales; however the Company has not engaged in any off-system sales during this determination period. The only margins received which are shared with the firm customers are capacity valuation margins received from the Company's Asset Manager. This credit is a fixed monthly payment which has been contractually agreed to by Chesapeake and its Asset Manager. Therefore, there is nothing for the Company's internal audit department to audit and no audit has been performed for this determination period. In regards to the other provisions, Ms. Kozel will be discussing the Company's gas procurement and open access activities.

Q. AS A RESULT OF COMMISSION ORDER NO. 7024 ISSUED ON SEPTEMBER 19, 2006 IN PSC DOCKET NO. 05-315F, WHAT ITEMS DID THE COMPANY INCLUDE IN THIS GSR FILING?

A. As a result of the settlement agreement in this proceeding, there were several items that the Company agreed to include in future filings. Among the items included in this application is an update on the steps the Company is taking to mitigate the effect of rising gas costs on customers, and details regarding the Asset Management procurement process.

Q. OVER THE PAST TWELVE MONTH PERIOD, WHAT STEPS HAS THE COMPANY TAKEN TO MITIGATE THE EFFECT OF GAS COSTS ON ITS CUSTOMERS?

A. The Company continues to encourage its customers to enroll in its budget billing program. This program provides for even monthly payments for the period of September through May. If necessary these monthly payments are adjusted midway through the winter in an attempt to avoid large credit or debit balances at the end of the budget period. The Company has included messages on its customers' bills during the months of June, July and August 2009 encouraging customers to sign up for the program, which begins in September. The Company also included a message about budget billing on its fall bill insert sent with its August bills. Additionally, the Company continues to promote conservation by including conservation tips on its customer's bills, as part of its customer guides, which are sent to each residential customer prior to every winter, and on a pamphlet available in its Dover office.

Q. ARE THERE ANY NEW DETAILS ABOUT THE COMPANY'S ASSET MANAGEMENT PROCUREMENT PROCESS?

A. Chesapeake entered into a new three-year agreement with its Asset Manager effective April 1, 2009. The details of the Company's activities with its Asset Manager are discussed in greater detail in the testimony of Marie Kozel.

Q. AS A RESULT OF COMMISSION ORDER NO. 7228 ISSUED ON JULY 24, 2007 IN PSC DOCKET NO. 06-287F, WHAT ITEMS DID THE COMPANY INCLUDE IN THIS GSR FILING?

A. As a result of the settlement agreement in this proceeding, there were two items that the Company agreed to include in future applications. First, the Company has agreed to submit an Annual Report of all of its hedging activities and transactions, including results. The Company considers this report to contain confidential information; therefore it is being submitted under separate cover. Second, Chesapeake has agreed to specify the amount of capacity charges for delivery points in eastern Sussex County, Delaware that the Company is seeking to recover in its GSR rates.

Q. WHAT PORTION OF THE FIRM TRANSPORTATION ENTITLEMENTS ON THE ESNG PIPELINE ARE FOR DELIVERY POINTS IN EASTERN SUSSEX COUNTY?

A. Effective November 1, 2009, Chesapeake will have a total of 4,204 Dt of firm transportation entitlements on the Eastern Shore pipeline at delivery points located in eastern Sussex County, Delaware at a total cost of approximately $874,461 per year. These costs are included in the GSR calculation in the same manner as are all other capacity costs for all of the Company's customers.

Q. AS A RESULT OF COMMISSION ORDER NO. 7607 ISSUED ON JULY 7, 2009 IN PSC DOCKET NO. 08-269F, WHAT INFORMATION HAS THE COMPANY INCLUDED IN THIS FILING?

A. As a result of the settlement agreement in this proceeding, the Company agreed to include the following information in this application:

1) The Company has agreed to provide the Parties with proposed changes to Chesapeake's gas commodity procurement plan.

2) Chesapeake will no longer be including a comparison of its GSR charges with other utilities in the area as part of its filing, but as a separate compliance filing no later than sixty (60) days later.

3) The Company has agreed to include the following information on its storage services; identification of which storages are under the control of Chesapeake, as opposed to its Asset Manager, the basis for the inventory balances reported, and how the Company manages the storages it controls.

4) The Company will continue to credit the GSR for 100% of the revenues received by the Company for any capacity released on the Eastern Shore transmission system.

5) The margin sharing mechanism related to the capacity valuation credit received from the Asset Manager has been modified to which Chesapeake will retain ten percent (10%) of the credits received by the Asset Manager, and credit the remaining ninety percent (90%) to the GSR rates.

6) The Company agreed to provide the total sales volumes, costs and margins by month (starting in September 2008) for interruptible gas transportation sales.

7) The Company has deferred $275,000 in prior capacity related costs and began recovering them, without carrying costs, over a seven year period, beginning in November 2008.

8) The Company agreed to identify and quantify any claims for cost recovery associated with the Eastern Shore Natural Gas ("Eastern Shore") E3 Project.

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED CHANGES TO THE NATURRAL GAS COMMODITY PROCUREMENT PLAN.

A. As I discussed earlier in my testimony, the Company considers the specific parameters of its commodity procurement plan to be confidential and therefore will be submitting its proposed changes under a separate cover.

Q, WHERE ARE THE DETAILS ON THE COMPANY'S STORAGE SERVICES ADDRESSED?

A. The specific details on the Company's storage services are addressed in the testimony of Marie Kozel.

Q. IN THIS FILING, WAS THE FULL BENEFIT OF PROJECTED CAPACITY RELEASES ON EASTERN SHORE'S SYSTEM CREDITED TO THE DELAWARE DIVISION FIRM RATEPAYERS?

A. Yes. The Company believes, as stated in prior GSR filings, that although the Settlement Agreement in PSC Docket No. 95-73, Phase II directed the Company to include margins from capacity release in the shared margin pool, the Company believes crediting 100% of the capacity released for the Delaware Division's firm transportation customers to the firm sales customers is appropriate due to the market on Eastern Shore for this capacity. The Company also credits 100% of any other Eastern Shore capacity releases to the firm sales customers. The specific details on the projected amount of capacity release revenues are included in the testimony of Michael Cassel.

Q. PLEASE DESCRIBE THE CHANGE IN THE MARGIN SHARING MECHANISM AS A RESULT OF PSC DOCKET NO. 08-269F.

A. The Company agreed to modify the margin sharing mechanism in regards to the capacity valuation credit received from its Asset Manager to a 90%/10% sharing beginning on November 1, 2009 with 90% being credited to the GSR. As shown on Schedule A.2, the new shared margin level was used in the calculation of the $0.012 per Ccf margin sharing rate, proposed to be effective November 1, 2009.

Q. HAS THE COMPANY COMPLIED WITH THE SETTLEMENT PROVISON IN WHICH IT WOULD PROVIDE TOTAL SALES VOLUMES, COSTS AND MARGINS BY MONTH FOR THE INTERRUPTIBLE TRANSPORTATION CUSTOMERS?

A. Yes. The settlement agreement in the last GSR proceeding allowed for this information to be submitted on a confidential basis; therefore, the Company will be submitting this detail under a separate cover.

Q. PLEASE DISCUSS HOW THE COMPANY COMPLIED WITH THE PROVISION RELATED TO THE TREATMENT OF $275,000 IN CAPACITY COSTS.

A. The Company included the actual adjustment on Schedule D.1 in the month of July 2009. Also, the amortized charges for this determination period are included on Schedule B as part of the demand rate.

Q. ARE THERE ANY COSTS ASSOCIATED WITH THE EASTERN SHORE E3 PROJECT INCLUDED IN THIS FILING?

A. Yes. The Company began incurring its portion of certain pre-certification costs associated with this project in May 2009 when Eastern Shore elected to terminate the project. The total amount of cost included in this filing is $306,299. Of this amount, $112,847 is for costs incurred during the twelve months ending October 2009 and is included as part of the over / under collection balance included on Schedule D.1. The remaining amount of $193,452 is related to costs to be incurred during the upcoming determination period and is included on Schedule B.

Q. PLEASE PROVIDE BACKGROUND INFORMATION ON THE E3 PROJECT.

A. In 2006, Eastern Shore announced a proposed expansion project called the Eastern Shore Energylink Expansion ("E3") Project. The project was intended to bring a new supply of clean burning natural gas to the Delmarva Peninsula, enabling ESNG's customers' diversification of their current supply mix. The project was to bring an additional 60,000 Dts of capacity to the region effectively enhancing overall natural gas reliability on the Peninsula and ensuring adequate supplies to meet the region's growing demand for many years. The project was for 63 miles of pipeline originating in Calvert County, MD at the site of Dominion Resources' liquefied natural gas facilities in Cove Point, MD, crossing under the Chesapeake Bay into Dorchester and Caroline Counties, MD and connecting with the existing Eastern Shore pipeline in Sussex County, DE. In May 2006, Eastern Shore entered into precedent agreements with Chesapeake's Delaware and Maryland Divisions and Delmarva Power and Light Company ("DPL"). The settlement agreement contained language whereby the participants in the project would share in the costs incurred in the event the project was terminated prior to completion of construction. The Federal Energy Regulatory Commission ("FERC") regulation allows for pipelines to negotiate rate related settlements outside of the context of an existing Commission proceeding and submit a petition for approval. This is preferable in that pipelines and their customers can resolve differences before making a filing which enables the quick processing of a settlement without the expense of a hearing and lengthy litigation. In a letter dated August 1, 2006, Eastern Shore received approval from FERC of the Settlement Agreement. Eastern Shore's filing with FERC for approval of the settlement agreement is included as Schedule N.1 and FERC's Order approving the settlement agreement is included as Schedule N.2

Q. PLEASE CONTINUE.

A. On January 9, 2008, Eastern Shore provided written notice of its withdrawal from the FERC pre-filing application process due to an increase in capital cost projections and a lack of market commitment. In May 2009, Eastern Shore informed the Delaware Division that it was electing to terminate the E3 project, pursuant to the terms of the precedent agreement, which gave either party the right to terminate the precedent agreement if a certificate application for the E3 Project had not been filed with FERC within twenty-four months after the date of the precedent agreement. Also in May 2009, Eastern Shore began billing monthly Chesapeake's Delaware and Maryland Divisions and DPL pursuant to the terms of its natural gas tariff as approved by FERC.

Q. WHAT WAS THE PRIMARY RATIONALE FOR ENTERING INTO A PRECEDENT AGREEMENT WITH EASTERN SHORE FOR THIS EXPANSION PROJECT?

A. Chesapeake believed the project would provide numerous benefits, including but not limited to, reducing the Company's dependence on Transcontinental Gas Pipe Line LLC ("Transco") and Columbia Gas Transmission LLC ("Columbia") as its sole sources of upstream pipeline capacity and provide access to competitively priced LNG supply from the Cove Point LNG facility. The Company had been relying on bundled peak supply for approximately 40% of its peak design day requirements at that time because alternative upstream capacity options for the Company had been limited. During the hurricane season of 2005, the Company had encountered challenges in securing firm Zone 6 delivered gas for the 2005-2006 determination period on Transco. It was and still is the Company's goal to secure adequate upstream capacity to serve its firm customers on a design day. In testimony filed by Commission Staff Witness Richard W. LeLash in 2007 in PSC Docket No. 06-287F, he stated, "Currently, and for the foreseeable future, the availability of alternative upstream capacity is limited and therefore the acquisition of Cove Point supply is warranted based on both reliability and economic considerations." The Cove Point supply was a viable alternative to the Company's growing reliance on bundled peaking supply which is susceptible to price volatility. Mr. LeLash went on to say, "...It is believed that the Cove Point Supply is a necessary and prudent capacity acquisition...In addition with its current customer and sales volume growth and the absence of alternative options for ESNG to augment its capacity to the south, the Company's capacity acquisition is justified to maintain its system reliability." In 2008 in PSC Docket No. 07-246F, Mr. LeLash states, "Despite the fact that the Company would have excess capacity for two or three years, the link to Cove Point was thought to be beneficial both in terms of system reliability and diversification."

Q. HAS THE COMPANY HAD ANY OTHER EXPERIENCES WITH PIPELINES REQUESTING RECOVERY OF A PORTION OF THE COSTS IF A PROJECT IS UNSUCCESSFUL?

A. Yes. The Company has seen similar language in the Sentinel Expansion Project Precedent Agreement it signed with Transco and other potential precedent agreements for projects that have been considered by the Company since that time.

Q. IS THE INFORMATION SET FORTH IN SCHEDULES A.1, A.2, B, C.1, C.2, D.1, D.2, E, F, G, H, I, J, L, M, N.1, and N.2 TRUE AND CORRECT TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes, it is.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?
A. Yes, it does.

DATED: SEPTEMBER 4, 2009

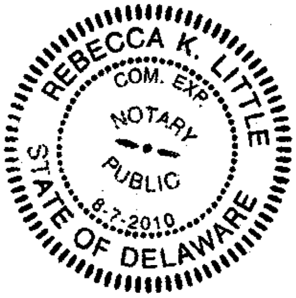
STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF JENNIFER A. CLAUSIUS

JENNIFER A. CLAUSIUS, being first duly sworn according to law, on oath deposes and says that she is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of Jennifer A. Clausius;" that, if asked the questions which appear in the text of the direct testimony, she would give the answers that are therein set forth; and that she adopts this testimony as her sworn direct testimony in these proceedings.

Jennifer A. Clausius
Jennifer A. Clausius

Then personally appeared this 4th day of September 2009 the above-named Jennifer A. Clausius and acknowledged the foregoing Testimony to be her free act and deed. Before me,



Rebecca K. Little
Notary Public
My Commission Expires: 8-7-2010

Chesapeake Utilities Corporation
Delaware Division
Development of Gas Sales Service Rates Effective November 1, 2009

Based on Total Firm Gas Costs Recoverable through GSR effective November 1, 2009

Description	Allocator	Total System Costs	Volume (Ccf)	Cost / Ccf
Fixed Gas Costs	Peak Day Capacity Entitlements	$15,820,014	621,266	$25.46
Variable Gas Costs	Annual Volume	$25,990,040	45,209,210	$0.575
Total Firm Gas Costs	Annual Volume	$41,810,055	45,209,210	$0.925

Development of High Load Factor Service Rates per CCF (74% Load Factor)

Description		Peak Day Cap. Method	System Average Cost	HLFS Average Rate
Demand Rate	($25.46 / 270)	$0.094		
Commodity Rate		$0.575		
Total Gas Sales Service Rate		**$0.669**	**$0.925**	**$0.797**

Total High Load Factor and Seasonal Firm Dollars

Projected Sales	Rate	Total Cost
11,467,640	**$0.797**	**$9,139,709**

Development of Gas Lighting Rate per CCF (100% Load Factor)

Description		Peak Day Cap. Method
Demand Rate	($25.46 / 365)	$0.070
Commodity Rate		$0.575
Total Gas Sales Service Rate		**$0.645**

Total Gas Lighting Dollars

Projected Sales	Rate	Total Cost
1,460	**$0.645**	**$942**

Development of RS1, RS2, GS, MVS, and LVS Rate per CCF

Description	Firm Gas Cost	Volume (CCF)	Rate per CCF	Margin Sharing Rate per CCF	Final Rate per CCF
Total System Gas Cost	$41,810,055	45,209,210			
Less : Allocated to HLFS	$9,139,709	11,467,640			
Less : Allocated to GL	$942	1,460			
Total Remaining System	$32,669,404	33,740,110	**$0.968**	**($0.012)**	**$0.956**

Schedule A.2
November 1, 2009

Chesapeake Utilities Corporation
Delaware Division
Development of Gas Sales Service Rates Effective November 1, 2009

Determination of Margin Sharing Credit for November 1, 2009 - October 31, 2010

Projected Interruptible Margin, Off-System Sales Margin and Capacity Valuation Credits for the Period

Description	2009 November Projected	2009 December Projected	2010 January Projected	2010 February Projected	2010 March Projected	2010 April Projected	2010 May Projected	2010 June Projected	2010 July Projected	2010 August Projected	2010 September Projected	2010 October Projected	Total
Off-System Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capacity Valuation	$32,314	$32,314	$32,314	$32,314	$32,314	$32,314	$32,314	$32,314	$32,314	$32,314	$32,314	$32,314	$387,768
Total Margins	$32,314	$32,314	$32,314	$32,314	$32,314	$32,314	$32,314	$32,314	$32,314	$32,314	$32,314	$32,314	$387,768

Amount of Margins Subject to Sharing to be Credited to RS-1,RS-2,GS,MVS,LVS Customers

Level of Margins Subject to Sharing	Eligible Margin Amounts	Customer Sharing (%)	Customer Sharing ($)
All Margins	$387,768	90%	$348,991
Total	$387,768		$348,991

Determination of Margin Sharing Credit Per Ccf For RS-1,RS-2,GS,MVS,LVS Customers

Month	Total Projected Firm Sales For Period	Gas Lighting Sales For Period		High Load Sales For Period	Projected RS-1,RS-2,GS, MVS & LVS Sales For Period
Nov-09	390,793	(13)		(132,230)	258,550
Dec-09	711,809	(13)		(228,661)	483,135
Jan-10	726,131	(12)		(91,235)	634,884
Feb-10	736,792	(12)		(84,451)	652,329
Mar-10	608,816	(12)		(81,995)	526,809
Apr-10	378,297	(12)		(76,521)	301,764
May-10	213,092	(12)		(63,878)	149,202
Jun-10	140,018	(12)		(59,160)	80,846
Jul-10	142,020	(12)		(75,857)	66,151
Aug-10	130,203	(12)		(72,561)	57,630
Sep-10	148,673	(12)		(81,129)	67,532
Oct-10	194,277	(12)		(99,086)	95,179
Total	4,520,921	(146)		(1,146,764)	3,374,011

Customer Sharing ($)	Prior Period Under Refund (Nov 08 - Oct 09)	Refund through Nov. 1, 2009 GSR	RS,GS,MVS, & LVS Sales In Ccf	Margin Sharing Rate Per Ccf
($348,991)	($47,201)	($396,192)	33,740,110	($0.012)

Chesapeake Utilities Corporation
Delaware Division
Current Firm Gas Costs
Effective November 1, 2009

	Total Gas Costs	Volume (Mcf)	Avg Cost/Mcf
Demand Rate:			
		62,127	
Upstream FT Reservation	$5,192,417		$83.578
Storage Demand & Capacity	$1,043,397		$16.795
ESNG FT Reservation	$10,799,840		$173.836
ESNG E3 Surcharge	$193,452		
Capacity Reservation	$184,276		$2.966
ESNG Capacity Release for Transp.	($1,401,759)		($22.563)
Balancing Rate Credit	($230,894)		($3.717)
Environmental Rider	$0		$0.000
GSR Settlement Adjustment	$39,286		
Supplier Refund	$0		$0.000
Total Firm Fixed Gas Costs	$15,820,014		$254.64
Peak Day Capacity (Mcf)	62,127		
Annual Fixed Cost per Mcf	$254.64		
Annual Fixed Cost per Ccf	$25.46		
Monthly Fixed Cost per Mcf	**$21.22**		
Monthly Fixed Cost per Ccf	**$2.122**		
Commodity Rate:			
		4,520,921	
Upstream FT Commodity	$26,354,986		$5.830
Storage I/W & Commodity	$3,718,078		$0.822
ESNG FT Commodity	$110,383		$0.024
Supplier Refund	($82,931)		($0.018)
Propane	$0		$0.000
CNG for Vehicular Use	($927)		($0.000)
(Over)/Under Collection	($4,109,549)		($0.909)
Transition Fees	$0		$0.000
Cash In/Cash Out	$0		$0.000
Total Firm Variable Gas Costs	$25,990,040		$5.75
Total Firm Sales Volumes (Mcf)	4,520,921		
Total Firm Sales Volumes (Ccf)	45,209,210		
Commodity Rate per Mcf	**$5.75**		
Commodity Rate per Ccf	**$0.575**		
System Average Rate:			
Total Firm Fixed Gas Costs	$15,820,014		
Total Firm Variable Gas Costs	$25,990,040		
Total Firm Gas Costs	**$41,810,055**	**4,520,921**	**$9.25**

Schedule C.1
November 1, 2009

Chesapeake Utilities Corporation
Projected Sales and Requirements Summary
November 1, 2009 - October 31, 2010

	Projected Nov-09	Projected Dec-09	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Total
Mcf Sales													
Firm													
Residential Service - 1	4,598	9,163	12,957	14,374	11,407	6,130	3,212	1,921	1,478	1,274	1,326	1,583	69,423
Residential Service - 2	159,330	289,876	418,614	431,475	350,390	204,523	101,058	52,432	39,759	34,536	36,579	54,498	2,173,070
General Service	14,574	32,864	52,031	57,070	43,680	21,537	10,993	5,094	4,035	3,552	4,099	4,979	254,508
Medium Volume Service	21,210	40,878	52,462	53,273	42,948	24,281	12,519	6,490	5,515	5,175	6,313	8,371	279,435
Large Volume Service	58,838	110,354	98,820	96,137	78,384	45,293	21,420	14,909	15,364	13,093	19,215	25,748	597,575
High Load Factor Service	132,230	228,661	91,235	84,451	81,995	76,521	63,878	59,160	75,857	72,561	81,129	99,086	1,146,764
Gas Lighting	13	13	12	12	12	12	12	12	12	12	12	12	146
Total Firm Mcf Sales	390,793	711,809	726,131	736,792	608,816	378,297	213,092	140,018	142,020	130,203	148,673	194,277	4,520,921
Natural Gas Vehicles	12	6	62	16	14	15	21	17	29	40	22	49	303
Total Mcf Sales	390,805	711,815	726,193	736,808	608,830	378,312	213,113	140,035	142,049	130,243	148,695	194,326	4,521,224
Mcf Requirements													
Mcf Sales	390,805	711,815	726,193	736,808	608,830	378,312	213,113	140,035	142,049	130,243	148,695	194,326	4,521,224
Adjusted Mcf Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Mcf Sales	390,805	711,815	726,193	736,808	608,830	378,312	213,113	140,035	142,049	130,243	148,695	194,326	4,521,224
Cycle Billing Adjustment	67,583	114,976	42,086	(81,421)	(73,847)	(80,360)	(30,483)	(3,033)	(4,277)	0	0	48,776	0
Subtotal	458,388	826,791	768,279	655,387	534,983	297,952	182,630	137,002	137,772	130,243	148,695	243,102	4,521,224
Company Use	108	345	421	396	330	131	31	25	20	94	76	14	1,991
Unaccounted For	9,915	17,630	15,314	11,272	9,085	4,525	3,105	2,624	2,636	2,467	2,848	5,494	86,915
Pressure Compensation	5,837	10,631	10,846	11,005	9,093	5,650	3,183	2,091	2,122	1,945	2,221	2,902	67,527
Total Mcf Requirements	474,248	855,398	794,860	678,059	553,491	308,258	188,949	141,742	142,550	134,749	153,840	251,512	4,677,656
Dt Requirements													
Total Dt Requirements	490,847	885,337	822,680	701,791	572,863	319,047	195,562	146,703	147,539	139,465	159,224	260,315	4,841,373

Chesapeake Utilities Corporation
Delaware Division

FIXED COSTS

	Projected November-09	Projected December-09	Projected January-10	Projected February-10	Projected March-10	Projected April-10	Projected May-10	Projected June-10	Projected July-10	Projected August-10	Projected September-10	Projected October-10	Total
Columbia Gas Transmission FT													
FTS Firm Transportation Service													
Reservation Rates	$6.0100	$6.0100	$6.0100	$6.0100	$6.0100	$6.0100	$6.0100	$6.0100	$6.0100	$6.0100	$6.0100	$6.0100	
Billing Units (MDTQ)	18,460	18,460	18,460	18,460	18,460	18,460	18,460	18,460	18,460	18,460	18,460	18,460	
Reservation Costs	$110,944.60	$110,944.60	$110,944.60	$110,944.60	$110,944.60	$110,944.60	$110,944.60	$110,944.60	$110,944.60	$110,944.60	$110,944.60	$110,944.60	$1,331,335.20
FTS-1 Columbia Gulf													
Reservation Rates	$3.1450	$3.1450	$3.1450	$3.1450	$3.1450	$3.1450	$3.1450	$3.1450	$3.1450	$3.1450	$3.1450	$3.1450	
Billing Units (MDTQ)	880	880	880	880	880	809	809	809	809	809	809	809	
Reservation Costs	$2,767.60	$2,767.60	$2,767.60	$2,767.60	$2,767.60	$2,544.31	$2,544.31	$2,544.31	$2,544.31	$2,544.31	$2,544.31	$2,544.31	$31,648.17
Columbia Reservation Costs	$113,712.20	$113,712.20	$113,712.20	$113,712.20	$113,712.20	$113,488.91	$113,488.91	$113,488.91	$113,488.91	$113,488.91	$113,488.91	$113,488.91	$1,362,983.37
Transco FT													
FT Firm Transportation													
Reservation Rates:													
Transco Zone 1 (Sta 30)													
Fixed Cost Rate	$0.4786	$0.4786	$0.4786	$0.4786	$0.4786	$0.4786	$0.4786	$0.4786	$0.4786	$0.4786	$0.4786	$0.4786	
Electric Power Rate	$0.00165	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	$0.0017	
Transco Zone 2 (Sta 45)													
Fixed Cost Rate	$0.45886	$0.4589	$0.4589	$0.4589	$0.4589	$0.4589	$0.4589	$0.4589	$0.4589	$0.4589	$0.4589	$0.4589	
Electric Power Rate	$0.00156	$0.0016	$0.0016	$0.0016	$0.0016	$0.0016	$0.0016	$0.0016	$0.0016	$0.0016	$0.0016	$0.0016	
Transco Zone 3 (Sta 50 and 62)													
Fixed Cost Rate	$0.43274	$0.4327	$0.4327	$0.4327	$0.4327	$0.4327	$0.4327	$0.4327	$0.4327	$0.4327	$0.4327	$0.4327	
Electric Power Rate	$0.00145	$0.0015	$0.0015	$0.0015	$0.0015	$0.0015	$0.0015	$0.0015	$0.0015	$0.0015	$0.0015	$0.0015	
Billing Units (MDTQ):													
Transco Zone 1 (Sta 30)	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889	
Transco Zone 2 (Sta 45)	2,778	2,778	2,778	2,778	2,778	2,778	2,778	2,778	2,778	2,778	2,778	2,778	
Transco Zone 3 (Sta 50 and 62)	6,445	6,445	6,445	6,445	6,446	6,445	6,445	6,445	6,445	6,445	6,445	6,445	
Total FT Units	11,112	11,112	11,112	11,112	11,112	11,112	11,112	11,112	11,112	11,112	11,112	11,112	
Reservation Costs:													
Transco Zone 1 (Sta 30)	$27,216.00	$28,123.20	$28,123.20	$25,401.60	$28,123.20	$27,216.00	$28,123.20	$27,216.00	$28,123.20	$28,123.20	$27,216.00	$28,123.20	$331,128.00
Transco Zone 2 (Sta 45)	$38,371.20	$39,650.24	$39,650.24	$35,813.12	$39,650.24	$38,371.20	$39,650.24	$38,371.20	$39,650.24	$39,650.24	$38,371.20	$39,650.24	$466,849.60
Transco Zone 3 (Sta 50 and 62)	$83,950.80	$86,749.16	$86,749.16	$78,354.08	$86,749.16	$83,950.80	$86,749.16	$83,950.80	$86,749.16	$86,749.16	$83,950.80	$86,749.16	$1,021,401.40
Transco Sub Total	$149,538.00	$154,522.60	$154,522.60	$139,568.80	$154,522.60	$149,538.00	$154,522.60	$149,538.00	$154,522.60	$154,522.60	$149,538.00	$154,522.60	$1,819,379.00
Transco Zone 5 (Cove Point)													
Reservation Rates	$0.5507	$0.5507	$0.5507	$0.5507	$0.5507	$0.5507	$0.5507	$0.5507	$0.5507	$0.5507	$0.5507	$0.5507	
Billing Units (MDTQ)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	
Reservation Costs	$165,210.00	$170,717.00	$170,717.00	$154,196.00	$170,717.00	$165,210.00	$170,717.00	$165,210.00	$170,717.00	$170,717.00	$165,210.00	$170,717.00	$2,010,055.00
Total Transco Reservation Costs	$314,748.00	$325,239.60	$325,239.60	$293,764.80	$325,239.60	$314,748.00	$325,239.60	$314,748.00	$325,239.60	$325,239.60	$314,748.00	$325,239.60	$3,829,434.00
Total Upstream Reservation Costs	$428,460.20	$438,951.80	$438,951.80	$407,477.00	$438,951.80	$428,236.91	$438,728.51	$428,236.91	$438,728.51	$438,728.51	$428,236.91	$438,728.51	$5,192,417.37

Chesapeake Utilities Corporation
Delaware Division

Eastern Shore Natural Gas	Projected November-09	Projected December-09	Projected January-10	Projected February-10	Projected March-10	Projected April-10	Projected May-10	Projected June-10	Projected July-10	Projected August-10	Projected September-10	Projected October-10	Total
FT/ST Firm Transportation - Zone 1													
Reservation Rates:													
Reservation - FT	$9.0271	$9.0271	$9.0271	$9.0271	$9.0271	$9.0271	$9.0271	$9.0271	$9.0271	$9.0271	$9.0271	$9.0271	
Billing Units (MDTQ):													
Reservation - FT	17,313	17,411	17,411	17,411	17,313	17,313	16,853	16,853	16,853	16,853	16,853	16,853	
Reservation - ST	400	400	400	400	400	400	145	145	145	145	145	145	
Reservation Costs:													
Reservation - FT	$156,286.18	$157,170.84	$157,170.84	$157,170.84	$156,286.18	$156,286.18	$152,133.72	$152,133.72	$152,133.72	$152,133.72	$152,133.72	$152,133.72	$1,853,173.38
Reservation - ST	$3,610.84	$3,610.84	$3,610.84	$3,610.84	$3,610.84	$3,610.84	$1,308.93	$1,308.93	$1,308.93	$1,308.93	$1,308.93	$1,308.93	$29,518.62
Reservation Costs - Zone 1	$159,897.02	$160,781.68	$160,781.68	$160,781.68	$159,897.02	$159,897.02	$153,442.65	$153,442.65	$153,442.65	$153,442.65	$153,442.65	$153,442.65	$1,882,692.00
FT Firm Transportation - Zone 2													
Reservation Rates:													
Reservation - FT	$17.3339	$17.3339	$17.3339	$17.3339	$17.3339	$17.3339	$17.3339	$17.3339	$17.3339	$17.3339	$17.3339	$17.3339	
Billing Units (MDTQ):													
Reservation - FT	42,088	43,212	43,212	43,212	42,088	42,088	36,707	36,707	36,707	36,707	36,707	36,707	
Reservation - ST	4,681	4,681	4,681	4,681	4,681	4,681	1,701	1,701	1,701	1,701	1,701	1,701	
Reservation Costs:													
Reservation - FT	$729,549.18	$749,032.49	$749,032.49	$749,032.49	$729,549.18	$729,549.18	$636,275.47	$636,275.47	$636,275.47	$636,275.47	$636,275.47	$636,275.47	$8,253,397.83
Reservation - ST	$81,139.99	$81,139.99	$81,139.99	$81,139.99	$81,139.99	$81,139.99	$29,484.96	$29,484.96	$29,484.96	$29,484.96	$29,484.96	$29,484.96	$663,749.70
Reservation Costs - Zone 2	$810,689.17	$830,172.48	$830,172.48	$830,172.48	$810,689.17	$810,689.17	$665,760.43	$665,760.43	$665,760.43	$665,760.43	$665,760.43	$665,760.43	$8,917,147.53
ESNG E-3 Surcharge	$16,121.01	$16,121.01	$16,121.01	$16,121.01	$16,121.01	$16,121.01	$16,121.01	$16,121.01	$16,121.01	$16,121.01	$16,121.01	$16,121.01	$193,452.12
Eastern Shore Reservation Costs	$986,707.20	$1,007,075.17	$1,007,075.17	$1,007,075.17	$986,707.20	$986,707.20	$835,324.09	$835,324.09	$835,324.09	$835,324.09	$835,324.09	$835,324.09	$10,993,291.65
Capacity Reservation	$0.00	$63,473.00	$63,473.00	$57,330.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$184,276.00
Capacity Release Credits	($116,636.14)	($120,037.78)	($120,123.01)	($122,985.70)	($116,673.56)	($113,669.88)	($116,153.54)	($112,803.19)	($114,454.82)	($112,951.47)	($118,707.90)	($116,561.59)	($1,401,758.58)
Storage Demand & Capacity													
Reservation Costs:													
Columbia:													
FSS Firm Storage Service	$149,041.40	$149,041.40	$149,041.40	$149,041.40	$149,041.40								$745,207.00
Transco:													
GSS General Storage Service	$24,407.55	$24,407.55	$24,407.55	$24,407.55	$24,407.55								$122,037.75
LGA Liquified Natural Gas Storage	$6,627.44	$6,627.44	$6,627.44	$6,627.44	$6,627.44								$33,137.20
LSS Leidy Storage Service	$7,722.67	$7,722.67	$7,722.67	$7,722.67	$7,722.67								$38,613.35
WSS Washington Storage Service	$5,037.73	$5,037.73	$5,037.73	$5,037.73	$5,037.73								$25,188.65
ESS Eminence Storage Service	$9,941.14	$9,941.14	$9,941.14	$9,941.14	$9,941.14								$49,705.70
EESWS Emergency Eminence Storage	$27.82	$27.82	$27.82	$27.82	$27.82								$139.10
PS Peaking Service	$5,873.57	$5,873.57	$5,873.57	$5,873.57	$5,873.56								$29,367.84
Total Transco	$59,637.92	$59,637.92	$59,637.92	$59,637.92	$59,637.91								$298,189.59
Total Storage Demand & Capacity Costs	$208,679.32	$208,679.32	$208,679.32	$208,679.32	$208,679.31								$1,043,396.59
TOTAL FIXED COSTS	$1,507,210.58	$1,598,141.51	$1,598,056.28	$1,557,575.79	$1,517,664.75	$1,301,274.23	$1,157,899.06	$1,150,757.81	$1,159,597.78	$1,161,101.13	$1,144,853.10	$1,157,491.01	$16,011,623.03

Chesapeake Utilities Corporation
Delaware Division

COMMODITY COSTS	Projected November-09	Projected December-09	Projected January-10	Projected February-10	Projected March-10	Projected April-10	Projected May-10	Projected June-10	Projected July-10	Projected August-10	Projected September-10	Projected October-10	Total
Columbia Gas Transmission FT													
Columbia - Gulf (FTS-1)													
Commodity Rate	$5.4753	$6.0394	$5.9158	$5.9720	$5.9441	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$6.4129	
Commodity in DT	25,781	26,691	26,691	23,247	25,830	0	0	0	0	0	0	3,168	131,408
Commodity Cost	$141,158.71	$161,197.63	$157,898.62	$138,831.08	$153,536.10	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$20,316.07	$772,938.21
Columbia - TCO 1278													
Commodity Rate	$0.0000	$6.9326	$8.0790	$7.7248	$6.4103	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Commodity in DT	0	124,021	9,965	35,499	21,123	0	0	0	0	0	0	0	190,608
Commodity Cost	$0.00	$859,787.98	$80,507.24	$274,222.68	$135,404.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,349,922.67
Swing Purchases - TCO (FTS)													
Commodity Rate	$4.8595	$5.6554	$6.0151	$6.1309	$6.0016	$5.9463	$6.0303	$5.9921	$6.1444	$0.0000	$0.0000	$6.4972	
Commodity in DT	42,049	68,379	78,002	56,857	52,535	23,979	4,047	3,206	4,042	0	0	8,381	341,477
Commodity Cost	$204,337.12	$386,710.60	$469,189.83	$348,584.58	$315,294.06	$142,586.33	$24,404.62	$19,210.67	$24,835.66	$0.00	$0.00	$54,453.03	$1,989,606.50
Total FTS Commodity Volume	67,830	219,091	114,658	115,603	99,488	23,979	4,047	3,206	4,042	0	0	11,549	663,493
Total FTS Commodity Costs	$345,495.83	$1,407,698.21	$707,595.69	$761,638.34	$604,234.93	$142,586.33	$24,404.62	$19,210.67	$24,835.66	$0.00	$0.00	$74,769.10	$4,112,467.38
TCO Pool through SST to ESNG													
Commodity Rate	$4.8595	$5.6554	$6.0151	$6.1309	$6.0016	$5.9463	$6.0303	$5.9921	$6.1444	$0.0000	$0.0000	$6.4972	
Commodity in DT	0	0	0	0	0	0	0	0	0	0	0	0	0
Commodity Cost	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Columbia Storage Injections													
Weighted Average Rate	$5.094	$6.425	$6.171	$6.588	$6.073	$5.946	$6.030	$5.992	$6.144	$0.000	$0.000	$6.474	
Commodity in DT	0	0	0	0	0	0	0	0	0	0	0	0	0
Commodity Cost	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Columbia Gas Transmission													
Commodity Volumes	67,830	219,091	114,658	115,603	99,488	23,979	4,047	3,206	4,042	0	0	11,549	663,493
Commodity Costs	$345,495.83	$1,407,696.21	$707,595.69	$761,638.34	$604,234.93	$142,586.33	$24,404.62	$19,210.67	$24,835.66	$0.00	$0.00	$74,769.10	$4,112,467.38
Transco FT													
FT Zone 1 to Zone 6 - (Sta 30)													
Commodity Rate	$5.4378	$6.0086	$6.2474	$5.8852	$5.7427	$5.8257	$6.0681	$6.1132	$6.1621	$6.2917	$6.2195	$6.0643	
Commodity in DT	56,670	60,202	60,202	54,376	58,559	41,280	43,183	41,280	43,183	43,183	41,339	43,823	587,280
Commodity Cost	$308,160.13	$361,729.74	$376,105.97	$320,013.64	$336,286.77	$240,484.90	$262,038.76	$252,352.90	$266,097.96	$271,694.48	$257,107.91	$265,755.82	$3,517,828.98
FT Zone 2 to Zone 6 - (Sta 45)													
Commodity Rate	$5.9160	$6.2945	$6.3950	$6.2772	$6.0332	$5.8970	$5.9830	$6.0493	$6.1963	$6.2566	$6.3777	$6.4875	
Commodity in DT	83,340	88,536	88,536	77,784	83,537	60,720	63,519	55,086	61,293	63,519	60,797	64,442	851,109
Commodity Cost	$493,039.44	$557,269.85	$566,187.72	$488,265.72	$503,995.43	$358,065.84	$380,034.18	$333,231.74	$379,789.82	$397,412.98	$387,745.03	$418,067.48	$5,263,125.23
FT Zone 3 to Zone 6 - (Sta 65)													
Commodity Rate	$4.7886	$5.7667	$6.1386	$6.0564	$5.9760	$5.8664	$6.0161	$6.1136	$6.2178	$6.2673	$6.4089	$6.5182	
Commodity in DT	151,897	196,026	205,375	169,947	171,002	150,783	84,727	36,178	38,186	32,931	57,279	138,959	1,433,290
Commodity Cost	$727,373.97	$1,130,423.13	$1,260,714.98	$1,029,267.01	$1,021,907.95	$884,553.39	$509,726.10	$221,177.82	$237,432.91	$206,388.46	$367,095.38	$905,762.55	$8,501,823.65
Total FT Commodity Volume	291,907	344,764	354,113	302,107	313,098	252,783	191,429	132,544	142,662	139,633	159,415	247,224	2,871,679
Total FT Commodity Costs	$1,528,573.54	$2,049,442.72	$2,203,008.67	$1,837,546.37	$1,862,190.15	$1,483,104.13	$1,151,799.04	$806,762.46	$883,320.69	$875,495.92	$1,011,948.32	$1,589,585.85	$17,282,777.86
FT Zone 5 to Zone 6 - (Cove Point)													
Commodity Rate	$4.9756	$6.3231	$7.0123	$6.8157	$6.1168	$5.9075	$6.0636	$6.1073	$6.2447	$0.0000	$0.0000	$6.5475	
Commodity in DT	57,960	231,806	184,402	160,227	78,479	42,668	321	11,129	1,012	0	0	1,855	769,859
Commodity Cost	$288,385.78	$1,465,732.52	$1,293,082.14	$1,092,059.16	$480,040.35	$252,061.21	$1,946.42	$67,968.14	$6,319.64	$0.00	$0.00	$12,145.81	$4,959,740.97
Swing Purchases - Transco Zone 6													
Commodity Rate	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
Commodity in DT	0	0	0	0	0	0	0	0	0	0	0	0	0
Commodity Cost	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transco Storage Injections													
Weighted Average Rate	$5.2365	$5.9445	$6.2212	$6.0824	$5.9476	$5.8671	$6.0168	$6.0868	$6.1917	$6.2700	$6.3479	$6.4297	
Commodity in DT	0	0	0	0	0	0	0	0	0	0	0	0	0
Commodity Cost	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transco													
Commodity Volume	349,867	576,570	538,515	462,334	391,577	295,451	191,750	143,673	143,674	139,633	159,415	249,079	3,641,538
Commodity Costs	$1,816,959.32	$3,515,175.24	$3,496,090.81	$2,929,605.53	$2,342,230.50	$1,735,165.34	$1,153,745.46	$874,730.60	$889,640.33	$875,495.92	$1,011,948.32	$1,601,731.46	$22,242,518.83

Chesapeake Utilities Corporation
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Storages		Projected November-09	Projected December-09	Projected January-10	Projected February-10	Projected March-10	Projected April-10	Projected May-10	Projected June-10	Projected July-10	Projected August-10	Projected September-10	Projected October-10	Total
Columbia Gas Transmission Storage														
FSS Firm Storage Service														
Charges:	Avg Commodity Inc Inj	$6.0714	$6.0714	$6.0714	$6.0714	$6.0714								
	Withdrawal Inc. Trans	$0.0153	$0.0153	$0.0153	$0.0153	$0.0153								
Billing Units:	Withdrawal	52,667	52,500	125,835	89,450	54,250								374,702
Cost:	Reservation	$149,041.40	$149,041.40	$149,041.40	$149,041.40	$149,041.40								$745,207.00
	Avg Commodity Inc Inj	$319,762.42	$318,748.50	$763,994.62	$543,086.73	$329,373.45								$2,274,965.72
	Withdrawal	$805.81	$803.25	$1,925.28	$1,368.59	$830.03								$5,732.96
		$469,609.63	$468,593.15	$914,961.30	$693,496.72	$479,244.88								$3,025,905.68
Transco Storages														
GSS General Storage Service														
Charges:	Avg Commodity Inc Inj	$6.7916	$6.7916	$6.7916	$6.7916	$6.7916								
	Withdrawal	$0.03946	$0.0395	$0.0395	$0.0395	$0.0395								
Billing Units:	Withdrawal	5,250	8,750	10,500	7,350	6,300								38,150
Cost:	Reservation	$24,407.55	$24,407.55	$24,407.55	$24,407.55	$24,407.55								$122,037.75
	Avg Commodity Inc Inj	$35,655.90	$59,426.50	$71,311.80	$49,918.26	$42,787.08								$259,099.54
	Withdrawal	$207.17	$345.28	$414.33	$290.03	$248.60								$1,505.41
		$60,270.62	$84,179.33	$96,133.68	$74,615.84	$67,443.23								$382,642.70
LGA Liquified Natural Gas Storage Service														
Charges:	Avg Commodity Inc Inj	$12.1473	$12.1473	$12.1473	$12.1473	$12.1473								
	Withdrawal	$1.36905	$1.3691	$1.3691	$1.3691	$1.3691								
	Withdrawal	0	0	0	0	0								0
Cost:	Reservation	$6,627.44	$6,627.44	$6,627.44	$6,627.44	$6,627.44								$33,137.20
	Avg Commodity Inc Inj	$0.00	$0.00	$0.00	$0.00	$0.00								$0.00
	Withdrawal	$0.00	$0.00	$0.00	$0.00	$0.00								$0.00
		$6,627.44	$6,627.44	$6,627.44	$6,627.44	$6,627.44								$33,137.20
LSS Leidy Storage Service														
Charges:	Avg Commodity Inc Inj	$6.8945	$6.8945	$6.8945	$6.8945	$6.8945								
	Withdrawal	$0.02195	$0.0220	$0.0220	$0.0220	$0.0220								
Billing Units:	Withdrawal	1,275	2,125	2,540	1,785	1,530								9,255
Cost:	Reservation	$7,722.67	$7,722.67	$7,722.67	$7,722.67	$7,722.67								$38,613.35
	Avg Commodity Inc Inj	$8,790.49	$14,650.81	$17,512.03	$12,306.68	$10,548.59								$63,808.60
	Withdrawal	$27.99	$46.64	$55.75	$39.18	$33.58								$203.14
		$16,541.15	$22,420.12	$25,290.45	$20,068.53	$18,304.84								$102,625.09
WSS Washington Storage Service														
Charges:	Avg Commodity Inc Inj	$9.3044	$9.3044	$9.3044	$9.3044	$9.3044								
	Withdrawal	$0.01295	$0.0130	$0.0130	$0.0130	$0.0130								
Billing Units:	Withdrawal	14,548	24,965	31,620	26,112	20,406								117,651
Cost:	Reservation	$5,037.73	$5,037.73	$5,037.73	$5,037.73	$5,037.73								$25,188.65
	Avg Commodity Inc Inj	$135,360.41	$232,284.35	$294,205.13	$242,956.49	$189,865.59								$1,094,671.97
	Withdrawal	$188.40	$323.30	$409.48	$338.15	$264.26								$1,523.59
		$140,586.54	$237,645.38	$299,652.34	$248,332.37	$195,167.58								$1,121,384.21
ESS Eminence Storage Service														
Charges:	Avg Commodity Inc Inj	$6.8778	$6.8778	$6.8778	$6.8778	$6.8778								
	Withdrawal	$0.02505	$0.0251	$0.0251	$0.0251	$0.0251								
Billing Units:	Withdrawal	0	2,400	0	0	0								2,400
Cost:	Reservation	$9,941.14	$9,941.14	$9,941.14	$9,941.14	$9,941.14								$49,705.70
	Avg Commodity Inc Inj	$0.00	$16,506.72	$0.00	$0.00	$0.00								$16,506.72
	Withdrawal	$0.00	$60.12	$0.00	$0.00	$0.00								$60.12
		$9,941.14	$26,507.98	$9,941.14	$9,941.14	$9,941.14								$66,272.54
EESWS Emergency Eminence Storage Service														
Charges:	Avg Commodity Inc Inj	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000								
	Withdrawal	$0.00000	$0.0000	$0.0000	$0.0000	$0.0000								
Billing Units:	Withdrawal	0	0	0	0	0								0
Cost:	Reservation	$27.82	$27.82	$27.82	$27.82	$27.82								$139.10
	Avg Commodity Inc Inj	$0.00	$0.00	$0.00	$0.00	$0.00								$0.00
	Withdrawal	$0.00	$0.00	$0.00	$0.00	$0.00								$0.00
		$27.82	$27.82	$27.82	$27.82	$27.82								$139.10
PS Peaking Service														
Charges:	Reservation	$5,873.57	$5,873.57	$5,873.57	$5,873.57	$5,873.56								$29,367.84
Columbia Storage Volume		52,667	52,500	125,835	89,450	54,250	0	0	0	0	0	0	0	374,702
Columbia Storage Commodity Costs		$320,568.23	$319,551.75	$765,919.90	$544,455.32	$330,203.48	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$2,280,698.68

Chesapeake Utilities Corporation
Delaware Division

	Projected November-09	Projected December-09	Projected January-10	Projected February-10	Projected March-10	Projected April-10	Projected May-10	Projected June-10	Projected July-10	Projected August-10	Projected September-10	Projected October-10	Total
Transco Storage Volume	21,073	38,240	44,660	35,247	28,236	0	0	0	0	0	0	0	167,456
Transco Storage Commodity Costs	$180,230.36	$329,643.72	$383,908.52	$305,848.79	$243,747.70	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,437,379.09
Total Storage Volume	73,740	90,740	170,495	124,697	82,486	0	0	0	0	0	0	0	542,158
Total Storage Commodity Costs	$500,798.59	$643,195.47	$1,149,828.42	$850,304.11	$573,951.18	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$3,718,077.77
Eastern Shore Natural Gas													
Total Upstream Volume	491,437	886,401	823,668	702,634	573,551	319,430	195,797	146,879	147,716	139,633	159,415	260,628	4,847,189
Eastern Shore Fuel	(590)	(1,064)	(988)	(843)	(688)	(383)	(235)	(176)	(177)	(168)	(191)	(313)	(5,816)
Eastern Shore Volume	490,847	885,337	822,680	701,791	572,863	319,047	195,562	146,703	147,539	139,465	159,224	260,315	4,841,373
Zone 1													
Commodity Rate	$0.0156	$0.0156	$0.0156	$0.0156	$0.0156	$0.0156	$0.0156	$0.0156	$0.0156	$0.0156	$0.0156	$0.0156	
Commodity In DT	0	0	0	0	0	0	0	0	0	0	0	0	
Commodity Cost	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Interruptible Commodity Rate	$0.3124	$0.3124	$0.3124	$0.3124	$0.3124	$0.3124	$0.3124	$0.3124	$0.3124	$0.3124	$0.3124	$0.3124	
Interruptible Commodity In DT	0	0	0	0	0	0	0	0	0	0	0	0	
Interruptible Commodity Cost	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Commodity Max Check	531,390	552,141	552,141	498,708	549,103	531,390	526,938	509,940	526,938	526,938	509,840	526,938	
Zone 2													
Commodity Rate	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	
Commodity in DT	490,847	885,337	822,680	701,791	572,863	319,047	195,562	146,703	147,539	139,465	159,224	260,315	
Commodity Cost	$11,191.31	$20,185.68	$18,757.10	$16,000.83	$13,061.28	$7,274.27	$4,458.81	$3,344.83	$3,363.89	$3,179.80	$3,630.31	$5,935.18	$110,383.29
Interruptible Commodity Rate	$0.5927	$0.5927	$0.5927	$0.5927	$0.5927	$0.5927	$0.5927	$0.5927	$0.5927	$0.5927	$0.5927	$0.5927	
Interruptible Commodity In DT	0	0	0	0	0	0	0	0	0	0	0	0	
Interruptible Commodity Cost	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Eastern Shore Commodity	$11,191.31	$20,185.68	$18,757.10	$16,000.83	$13,061.28	$7,274.27	$4,458.81	$3,344.83	$3,363.89	$3,179.80	$3,630.31	$5,935.18	$110,383.29
TOTAL COMMODITY COSTS	$2,674,445.05	$5,586,252.60	$5,372,272.02	$4,557,548.81	$3,533,477.89	$1,885,025.94	$1,182,608.89	$897,266.10	$917,839.88	$878,675.72	$1,015,578.63	$1,882,435.74	$30,183,447.27

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	Projected November-09	Projected December-09	Projected January-10	Projected February-10	Projected March-10	Projected April-10	Projected May-10	Projected June-10	Projected July-10	Projected August-10	Projected September-10	Projected October-10	Total
Summary													
Columbia Gas Transmission													
Columbia/Columbia Gulf FT Costs													
Fixed Costs	$113,712.20	$113,712.20	$113,712.20	$113,712.20	$113,712.20	$113,488.91	$113,488.91	$113,488.91	$113,488.91	$113,488.91	$113,488.91	$113,488.91	$1,362,983.37
Commodity Costs	$345,495.83	$1,407,696.21	$707,595.69	$761,638.34	$604,234.93	$142,586.33	$24,404.62	$19,210.67	$24,835.66	$0.00	$0.00	$74,769.10	$4,112,467.38
Total Costs	$459,208.03	$1,521,408.41	$821,307.89	$875,350.54	$717,947.13	$256,075.24	$137,893.53	$132,699.58	$138,324.57	$113,488.91	$113,488.91	$188,258.01	$5,475,450.75
Columbia/Columbia Gulf Storage Costs													
Fixed Costs	$149,041.40	$149,041.40	$149,041.40	$149,041.40	$149,041.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$745,207.00
Commodity Costs	$320,568.23	$319,551.75	$765,919.90	$544,455.32	$330,203.48	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$2,280,698.68
Total Costs	$469,609.63	$468,593.15	$914,961.30	$693,496.72	$479,244.88	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$3,025,905.68
Columbia/Columbia Gulf Total Costs													
Fixed Costs	$262,753.60	$262,753.60	$262,753.60	$262,753.60	$262,753.60	$113,488.91	$113,488.91	$113,488.91	$113,488.91	$113,488.91	$113,488.91	$113,488.91	$2,108,190.37
Commodity Costs	$666,064.06	$1,727,247.96	$1,473,515.59	$1,306,093.66	$934,438.41	$142,586.33	$24,404.62	$19,210.67	$24,835.66	$0.00	$0.00	$74,769.10	$6,393,166.06
Total Costs	$928,817.66	$1,990,001.56	$1,736,269.19	$1,568,847.26	$1,197,192.01	$256,075.24	$137,893.53	$132,699.58	$138,324.57	$113,488.91	$113,488.91	$188,258.01	$8,501,356.43
Columbia FT Volume	67,830	219,091	114,658	115,603	99,488	23,979	4,047	3,206	4,042	0	0	11,549	663,493
Columbia Storage Volume	52,667	52,500	125,835	89,450	54,250	0	0	0	0	0	0	0	374,702
Columbia Total Volume	120,497	271,591	240,493	205,053	153,738	23,979	4,047	3,206	4,042	0	0	11,549	1,038,195
Transco													
Transco FT Totals													
Fixed Costs	$314,748.00	$325,239.60	$325,239.60	$283,764.80	$325,239.60	$314,748.00	$325,239.60	$314,748.00	$325,239.60	$325,239.60	$314,748.00	$325,239.60	$3,829,434.00
Commodity Costs	$1,816,959.32	$3,515,175.24	$3,496,090.81	$2,928,605.53	$2,342,230.50	$1,735,165.34	$1,153,745.46	$874,730.60	$889,640.33	$875,495.92	$1,011,948.32	$1,601,731.46	$22,242,518.83
Total Costs	$2,131,707.32	$3,840,414.84	$3,821,330.41	$3,223,370.33	$2,667,470.10	$2,049,913.34	$1,478,985.06	$1,189,478.60	$1,214,879.93	$1,200,735.52	$1,326,696.32	$1,926,971.06	$26,071,952.83
Transco Storage Cost Totals													
Fixed Costs	$59,637.92	$59,637.92	$59,637.92	$59,637.92	$59,637.91	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$298,189.59
Commodity Costs	$180,230.36	$323,643.72	$383,908.52	$305,848.79	$243,747.70	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,437,379.09
Total Costs	$239,868.28	$383,281.64	$443,546.44	$365,486.71	$303,385.61	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,735,568.68
Transco Total Costs													
Fixed Costs	$374,385.92	$384,877.52	$384,877.52	$353,402.72	$384,877.51	$314,748.00	$325,239.60	$314,748.00	$325,239.60	$325,239.60	$314,748.00	$325,239.60	$4,127,623.59
Commodity Costs	$1,997,189.68	$3,838,818.96	$3,879,999.33	$3,235,454.32	$2,585,978.20	$1,735,165.34	$1,153,745.46	$874,730.60	$889,640.33	$875,495.92	$1,011,948.32	$1,601,731.46	$23,679,897.92
Total Costs	$2,371,575.60	$4,223,696.48	$4,264,876.85	$3,588,857.04	$2,970,855.71	$2,049,913.34	$1,478,985.06	$1,189,478.60	$1,214,879.93	$1,200,735.52	$1,326,696.32	$1,926,971.06	$27,807,521.51
Transco FT Volume	349,867	576,570	538,515	462,334	391,577	295,451	191,750	143,673	143,674	139,633	159,415	249,079	3,641,538
Transco Storage Volume	21,073	38,240	44,660	35,247	28,236	0	0	0	0	0	0	0	167,456
Transco Total Volume	370,940	614,810	583,175	497,581	419,813	295,451	191,750	143,673	143,674	139,633	159,415	249,079	3,808,994
Eastern Shore Natural Gas													
Fixed Costs	$986,707.20	$1,007,075.17	$1,007,075.17	$1,007,075.17	$986,707.20	$986,707.20	$835,324.09	$835,324.09	$835,324.09	$835,324.09	$835,324.09	$835,324.09	$10,993,291.65
Commodity Costs	$11,191.31	$20,185.68	$18,757.10	$16,000.83	$13,061.28	$7,274.27	$4,458.81	$3,344.83	$3,363.89	$3,179.80	$3,630.31	$5,935.18	$110,383.29
Total Costs	$997,898.51	$1,027,260.85	$1,025,832.27	$1,023,076.00	$999,768.48	$993,981.47	$839,782.90	$838,668.92	$838,687.98	$838,503.89	$838,954.40	$841,259.27	$11,103,674.94
Total Commodity Volume	417,697	795,681	653,173	577,937	491,065	319,430	195,797	146,879	147,716	139,633	159,415	260,628	4,305,031
Total Storage Volume	73,740	90,740	170,495	124,697	82,486	0	0	0	0	0	0	0	542,158
Total Volume	491,437	886,401	823,668	702,634	573,551	319,430	195,797	146,879	147,716	139,633	159,415	260,628	4,847,189

Chesapeake Utilities Corporation
Delaware Division

	Projected November-09 1.035	Projected December-09 1.035	Projected January-10 1.035	Projected February-10 1.035	Projected March-10 1.035	Projected April-10 1.035	Projected May-10 1.035	Projected June-10 1.035	Projected July-10 1.035	Projected August-10 1.035	Projected September-10 1.035	Projected October-10 1.035	Total 1.035
Flowing Commodity WACOG													
Transco Station 30	$308,160.13	$361,729.74	$376,105.97	$320,013.64	$336,286.77	$240,484.90	$262,038.76	$252,352.90	$266,097.96	$271,694.48	$257,107.91	$265,755.82	$3,517,828.98
Transco Station 45	$493,039.44	$557,289.85	$566,187.72	$488,265.72	$503,995.43	$358,065.84	$380,034.16	$333,231.74	$379,789.82	$397,412.98	$387,745.03	$418,087.48	$5,263,125.23
Transco Station 65	$727,373.97	$1,130,423.13	$1,280,714.98	$1,029,267.01	$1,021,907.95	$884,553.39	$509,726.10	$221,177.82	$237,432.91	$206,388.46	$387,095.38	$905,762.55	$8,501,823.65
Transco Storage Injections	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transco Zone 5 (Cove Point)	$288,365.78	$1,465,732.52	$1,293,082.14	$1,092,059.16	$480,040.35	$252,061.21	$1,946.42	$67,968.14	$6,319.64	$0.00	$0.00	$12,145.61	$4,959,740.97
UP Transco 6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
UP - TCO Pool	$204,337.12	$386,710.60	$469,189.83	$348,584.56	$315,294.06	$142,588.33	$24,404.62	$19,210.67	$24,835.66	$0.00	$0.00	$54,453.03	$1,989,606.50
Columbia Rayne	$141,158.71	$161,197.63	$157,898.62	$138,831.08	$153,536.10	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$20,316.07	$772,938.21
Columbia Storage Injections	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ESNG Imbalance	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	$2,162,455.15	$4,063,083.47	$4,123,179.26	$3,417,021.19	$2,811,060.66	$1,877,751.67	$1,178,150.08	$893,941.27	$914,475.99	$875,495.92	$1,011,948.32	$1,676,500.56	$25,005,063.54
Dt	417,154	794,627	652,324	577,186	490,427	319,015	195,542	146,688	147,524	139,451	159,208	260,289	4,299,435
Unit Cost per Dt	$5.1838	$5.1132	$6.3208	$5.9201	$5.7319	$5.8861	$6.0250	$6.0942	$6.1988	$6.2762	$6.3561	$6.4409	$5.8159
Unit Cost per Dt w/ESN Com	$5.2066	$5.1360	$6.3436	$5.9429	$5.7547	$5.9089	$6.0478	$6.1170	$6.2216	$6.3010	$6.3789	$6.4637	$5.8387
Unit Cost per Mcf w/ESN Com	$5.3888	$5.3158	$6.5656	$6.1509	$5.9561	$6.1157	$6.2595	$6.3311	$6.4394	$6.5215	$6.6022	$6.6899	$6.0431
Unit Cost per Mcf w/ESN Com + UFG	$5.5753	$5.4997	$6.7928	$6.3637	$6.1622	$6.3273	$6.4761	$6.5502	$6.6622	$6.7471	$6.8306	$6.9214	$6.2522
TOTAL COSTS													
Fixed Costs													
Upstream FT Reservation	$428,460.20	$438,951.80	$438,951.80	$407,477.00	$438,951.80	$428,236.91	$438,728.51	$428,236.91	$438,728.51	$438,728.51	$428,236.91	$438,728.51	$5,192,417.37
Storage Demand & Capacity	$208,679.32	$208,679.32	$208,678.32	$208,679.32	$208,679.31	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,043,396.59
ESNG FT Reservation	$986,707.20	$1,007,075.17	$1,007,075.17	$1,007,075.17	$986,707.20	$986,707.20	$835,324.09	$835,324.09	$835,324.09	$835,324.09	$835,324.09	$835,324.09	$10,993,291.65
Add: Capacity Reservation	$0.00	$63,473.00	$63,473.00	$57,330.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$184,276.00
Less: Capacity Release Credits	($116,636.14)	($120,037.78)	($120,123.01)	($122,985.70)	($116,673.56)	($113,669.88)	($116,153.54)	($112,803.19)	($114,454.62)	($112,951.47)	($118,707.90)	($116,561.59)	($1,401,758.58)
Fixed Costs	$1,507,210.58	$1,598,141.51	$1,598,056.28	$1,557,575.79	$1,517,664.75	$1,301,274.23	$1,157,899.06	$1,150,757.81	$1,159,597.78	$1,161,101.13	$1,144,853.10	$1,157,491.01	$16,011,623.03
Commodity Costs													
Upstream FT Commodity	$2,162,455.15	$4,922,871.45	$4,203,686.50	$3,691,243.87	$2,946,465.43	$1,877,751.67	$1,178,150.08	$893,941.27	$914,475.99	$875,495.92	$1,011,948.32	$1,676,500.56	$26,354,986.21
Storage IW & Commodity	$500,798.59	$643,195.47	$1,149,828.42	$850,304.11	$573,951.18	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$3,716,077.77
ESNG FT Commodity	$11,191.31	$20,185.68	$18,757.10	$16,000.83	$13,061.28	$7,274.27	$4,458.81	$3,344.83	$3,363.89	$3,179.80	$3,630.31	$5,935.18	$110,383.29
Commodity Costs	$2,674,445.05	$5,586,252.60	$5,372,272.02	$4,557,548.81	$3,533,477.89	$1,885,025.94	$1,182,608.89	$897,286.10	$917,839.88	$878,675.72	$1,015,578.63	$1,682,435.74	$30,183,447.27
Less: CNG Use	$0.00	($142.88)	($57.58)	($20.07)	($210.48)	$0.00	($67.92)	($116.64)	($90.72)	($77.76)	($77.76)	($64.80)	($926.61)
Total Firm Cost of Gas	$4,181,655.63	$7,184,536.99	$6,970,385.86	$6,115,144.67	$5,051,353.12	$3,186,300.17	$2,340,575.87	$2,048,160.55	$2,077,528.38	$2,039,854.61	$2,160,509.49	$2,839,991.55	$46,195,996.91

Schedule D.1
November 1, 2009

Chesapeake Utilities Corporation
Delaware Division
Projected Gas Cost Over/(Under) Collection
For The Twelve Months Ending October 31, 2009

	Actual Nov-08	Actual Dec-08	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Total
Calculation of Current Over/(Under) Collections													
GSR Revenue (RS, GS, MVS, LVS)	$3,254,868.56	$7,305,869.22	$9,944,120.38	$8,066,927.15	$6,629,787.20	$3,809,129.83	$1,681,479.61	$888,350.74	$755,448.15	$878,243.10	$1,098,898.15	$1,632,088.50	$45,945,210.59
GSR Revenue (HLFS, SFS)	$720,275.82	$955,057.40	$1,018,449.37	$819,886.72	$823,226.88	$773,675.87	$607,426.54	$557,451.20	$513,493.03	$570,553.60	$637,648.40	$761,513.00	$8,758,657.83
GSR Revenue (GLR, GLO, GCR, GCO)	$126.48	$141.83	$141.83	$116.71	$115.71	$116.71	$116.71	$116.71	$116.71	$132.73	$132.73	$132.73	$1,508.59
Total GSR Revenue	$3,975,270.86	$8,261,068.45	$10,962,711.58	$8,886,930.58	$7,453,130.79	$4,582,922.41	$2,289,022.86	$1,445,918.65	$1,269,057.89	$1,448,929.43	$1,736,679.28	$2,393,734.23	$54,705,377.01
Less: Regulatory Assessment	$11,925.81	$24,783.21	$32,888.13	$26,660.79	$22,359.39	$13,748.77	$6,867.07	$4,337.76	$3,807.17	$4,346.79	$5,210.04	$7,181.20	$164,116.13
Net Collections	$3,963,345.05	$8,236,285.24	$10,929,823.45	$8,860,269.79	$7,430,771.40	$4,569,173.64	$2,282,155.79	$1,441,580.89	$1,265,250.72	$1,444,582.64	$1,731,469.24	$2,386,553.03	$54,541,260.88
Natural Gas Cost	$5,166,198.99	$7,232,751.54	$9,937,348.05	$6,584,539.75	$6,140,761.17	$2,956,981.62	$1,997,668.43	$1,668,752.73	$1,599,883.86	$1,784,734.07	$2,028,159.17	$2,540,766.73	$49,638,546.11
Propane Costs	$0.00	$3,113.49	$15,620.34	$0.00	$2,295.44	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$21,029.27
Cost of Interruptible Sales	($133,276.63)	($152,614.73)	($612.50)	($147.11)	($116.98)	($129.93)	($129.74)	($117.51)	($124.55)	$0.00	$0.00	$0.00	($287,269.68)
GSR Settlement Adjustment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	($252,238.84)	$3,273.81	$3,273.81	$3,273.81	($242,417.41)
Prior Period Adjustments to Interest	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Transition Fee	($16,335.94)	($1.45)	($16,445.69)	$0.00	$0.00	($2,915.96)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	($35,699.04)
Miscellaneous Adjustments	$0.00	$5,166.61	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$5,166.61
Transportation Balancing Rate Credit	($20,961.10)	($32,719.61)	($31,492.08)	($28,410.08)	($28,005.41)	($24,173.90)	($19,449.86)	($19,587.10)	($21,014.16)	($11,328.00)	($15,389.00)	($18,568.00)	($271,198.30)
Transportation Cash In/Out Credit	$57,745.32	$109,658.97	($68,811.44)	$66,304.95	($1,767.90)	$29,665.26	$68,330.98	$68,123.30	$84,394.31	$0.00	$0.00	$0.00	$413,643.75
Net Cost	$5,053,370.64	$7,165,354.82	$9,835,606.68	$6,622,287.51	$6,113,166.32	$2,959,427.09	$2,046,419.81	$1,717,071.42	$1,410,900.62	$1,776,679.88	$2,016,043.98	$2,525,472.54	$49,241,801.31
Current (Over)/Under Collection	$1,090,025.59	($1,070,930.42)	($1,094,216.77)	($2,237,982.28)	($1,317,605.08)	($1,609,746.55)	($235,735.98)	$275,490.53	$145,649.90	$332,097.24	$284,574.74	$138,919.51	($5,299,459.57)
Calculation of Carrying Charge on Account #191													
Balance in #191 in the Beginning of Month	$1,476,214.00	$2,512,938.72	$1,436,916.24	$327,548.90	($1,909,716.98)	($3,231,685.45)	($4,846,938.70)	($5,179,543.25)	($4,979,729.05)	($4,842,754.84)	($4,518,648.89)	($4,241,536.17)	
Prior Period Adjustments	($50,742.40)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Prior Period Adjustments to Interest	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	($29,464.29)	($3,273.81)	($3,273.81)	($3,273.81)	
Adjusted Beginning Balance	$1,425,471.60	$2,512,938.72	$1,436,916.24	$327,548.90	($1,909,716.98)	($3,231,685.45)	($4,846,938.70)	($5,179,543.25)	($5,009,193.34)	($4,846,028.65)	($4,521,922.70)	($4,244,809.98)	
Times Effective Tax Rate	39.742%	39.742%	39.742%	39.742%	39.742%	39.742%	39.742%	39.742%	39.742%	39.742%	39.742%	39.742%	
Deferred Income Tax	$566,510.92	$998,692.11	$571,059.25	$130,174.48	($758,959.72)	($1,284,336.43)	($1,926,270.38)	($2,058,454.08)	($1,990,753.62)	($1,925,908.71)	($1,797,102.52)	($1,686,972.38)	($11,162,321.08)
Balance Net of Income Tax	$858,960.68	$1,514,246.61	$865,856.99	$197,374.42	($1,150,757.26)	($1,947,349.02)	($2,920,668.32)	($3,121,089.17)	($3,018,439.72)	($2,920,119.94)	($2,724,820.18)	($2,557,837.60)	($16,924,642.51)
Times 1/12 of Annual Interest Rate	0.417%	0.417%	0.377%	0.377%	0.377%	0.281%	0.281%	0.281%	0.271%	0.271%	0.271%	0.271%	
Interest (Revenue) or Expense	$3,581.87	$6,314.41	$3,264.28	$744.10	($4,338.35)	($5,472.05)	($8,207.08)	($8,770.26)	($8,179.97)	($7,913.53)	($7,384.26)	($6,931.74)	($43,292.58)
Calculation of Ending Balance in Account #191													
Balance in #191 in the Beginning of Period	$1,425,471.60	$2,512,938.72	$1,436,916.24	$327,548.90	($1,909,716.98)	($3,231,685.45)	($4,846,938.70)	($5,179,543.25)	($4,979,729.05)	($4,842,754.84)	($4,518,648.89)	($4,241,536.17)	$1,425,471.60
Current (Over)/Under Collections	$1,090,025.59	($1,070,930.42)	($1,094,216.77)	($2,237,982.28)	($1,317,605.08)	($1,609,746.55)	($235,735.98)	$275,490.53	$145,649.90	$332,097.24	$284,574.74	$138,919.51	($5,299,459.57)
Supplier Refunds	($6,122.63)	($11,397.77)	($18,348.24)	$0.00	$0.00	$0.00	($88,575.00)	($66,620.50)	($340.03)	$0.00	$0.00	$0.00	($191,404.17)
CNG Vehicular Fuel	($17.71)	($8.70)	($66.61)	($27.58)	($25.07)	($34.65)	($86.49)	($221.19)	($155.69)	($77.76)	($77.76)	($64.80)	($864.01)
Interest Revenue or (Expense)	$3,581.87	$6,314.41	$3,264.28	$744.10	($4,338.35)	($5,472.05)	($8,207.08)	($8,770.26)	($8,179.97)	($7,913.53)	($7,384.26)	($6,931.74)	($43,292.58)
Ending Balance #191 (Over)/Under Collections	$2,512,938.72	$1,436,916.24	$327,548.90	($1,909,716.98)	($3,231,685.45)	($4,846,938.70)	($5,179,543.25)	($4,979,729.05)	($4,842,754.84)	($4,518,648.89)	($4,241,536.17)	($4,109,613.20)	($4,109,548.73)
RS, GS, MVS, LVS Mcf's	231,481	485,125	650,300	626,772	515,922	295,995	130,669	69,045	57,903	67,818	84,857	126,030	3,351,917
HLFS, SFS Mcf's	54,608	68,763	73,219	69,956	70,242	66,013	51,828	47,564	43,813	48,352	54,038	64,535	712,931
GLR, GLO, GCR, GCO Mcf's	12	12	12	12	12	12	12	12	12	13	13	13	147
Total Firm Mcf's + Adjusted Sales	286,101	553,900	733,531	696,740	586,176	362,020	182,509	116,621	101,728	116,183	138,908	190,578	4,064,995
RS, GS, MVS, LVS GSR Rate	$15.06	$15.06	$15.06	$12.95	$12.95	$12.95	$12.95	$12.95	$12.95	$12.95	$12.95	$12.95	
HLFS Rate	$13.91	$13.91	$13.91	$11.80	$11.80	$11.80	$11.80	$11.80	$11.80	$11.80	$11.80	$11.80	
GLR, GLO Rate	$12.31	$12.31	$12.31	$10.21	$10.21	$10.21	$10.21	$10.21	$10.21	$10.21	$10.21	$10.21	
Annual Interest Rate	5.000%	5.000%	4.520%	4.520%	4.520%	3.370%	3.370%	3.370%	3.250%	3.250%	3.250%	3.250%	
Effective Tax Rate	39.742%	39.742%	39.742%	39.742%	39.742%	39.742%	39.742%	39.742%	39.742%	39.742%	39.742%	39.742%	
Supplier Refunds	$6,122.63	$11,397.77	$18,348.24	$0.00	$0.00	$0.00	$88,575.00	$66,620.50	$340.03	$0.00	$0.00	$0.00	

Schedule D.2
November 1, 2009

Chesapeake Utilities Corporation
Delaware Division
Projected Shared Margins Over/(Under) Refund
For The Twelve Months Ending October 31, 2009

	Actual Nov-08	Actual Dec-08	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Projected Aug-09	Projected Sep-09	Projected Oct-09	Total
Calculation of Current Shared Margins Over/(Under) Refund													
Total Shared Margins	$19,512.00	$19,512.00	$19,512.00	$19,512.00	$19,512.00	$32,314.00	$32,314.00	$32,314.00	$32,314.00	$32,314.00	$32,314.00	$32,314.00	$323,758.00
Shared Margin Inherent in Rate	$101,851.64	$194,050.00	$264,120.00	$275,779.68	$227,005.68	$130,237.80	$57,494.36	$30,379.80	$25,477.32	$29,839.92	$37,337.08	$55,453.20	$1,429,026.48
Less: Regulatory Assessment	$305.55	$582.15	$792.36	$827.34	$681.02	$390.71	$172.48	$91.14	$76.43	$89.52	$112.01	$166.36	$4,287.07
Net Margin Refunded Through Rate	$101,546.09	$193,467.85	$263,327.64	$274,952.34	$226,324.66	$129,847.09	$57,321.88	$30,288.66	$25,400.89	$29,750.40	$37,225.07	$55,286.84	$1,424,739.41
Shared Margins Expensed	($15,473.53)	($15,610.00)	($15,610.00)	($15,610.00)	($15,610.00)	($25,851.20)	($25,851.00)	($25,851.00)	($25,851.00)	($25,851.20)	($25,851.20)	($25,851.20)	($258,871.33)
Current Over/(Under) Refund	$86,072.56	$177,857.85	$247,717.64	$259,342.34	$210,714.66	$103,995.89	$31,470.88	$4,437.66	($450.11)	$3,899.20	$11,373.87	$29,435.64	$1,165,868.08
Calculation of Ending Balance in Account #191SM													
Balance in #191SM in the Beginning of Period	($1,213,069.19)	($1,126,996.63)	($949,138.78)	($701,421.14)	($442,078.80)	($231,364.14)	($127,368.25)	($95,897.37)	($91,459.71)	($91,909.82)	($88,010.62)	($76,636.75)	($1,213,069.19)
Prior Period Adjustment	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Adjusted Beginning Balance	($1,213,069.19)	($1,126,996.63)	($949,138.78)	($701,421.14)	($442,078.80)	($231,364.14)	($127,368.25)	($95,897.37)	($91,459.71)	($91,909.82)	($88,010.62)	($76,636.75)	($1,213,069.19)
Current Over/(Under) Refund	$86,072.56	$177,857.85	$247,717.64	$259,342.34	$210,714.66	$103,995.89	$31,470.88	$4,437.66	($450.11)	$3,899.20	$11,373.87	$29,435.64	$1,165,868.08
Ending Balance #191SM Over/(Under) Refund	($1,126,996.63)	($949,138.78)	($701,421.14)	($442,078.80)	($231,364.14)	($127,368.25)	($95,897.37)	($91,459.71)	($91,909.82)	($88,010.62)	($76,636.75)	($47,201.11)	($47,201.11)
RS, GS, MVS, LVS Mcf's	231,481	485,125	660,300	626,772	515,922	295,995	130,669	69,045	57,903	67,818	84,857	126,030	3,351,917
Margin Sharing Credit Per Mcf	$0.44	$0.40	$0.40	$0.44	$0.44	$0.44	$0.44	$0.44	$0.44	$0.44	$0.44	$0.44	

Schedule E
November 1, 2009

Chesapeake Utilities Corporation
Delaware Division
Development of Gas Sales Service Rates Effective November 1, 2009

Based on Total Firm Gas Costs Recoverable through GSR effective November 1, 2009

Description	Allocator	Total System Costs	Volume (Ccf)	Cost / Ccf
Fixed Gas Costs	Peak Day Capacity Entitlements	$15,820,014	621,266	$25.46
Variable Gas Costs	Annual Volume	$25,990,040	45,209,210	$0.575
Total Firm Gas Costs	Annual Volume	$41,810,055	45,209,210	$0.925

Development of High Load Factor Service Rates per CCF (54% Load Factor)

Description		Peak Day Cap. Method	System Average Cost	HLFS Average Rate
Demand Rate	($25.46 / 270)	$0.129		
Commodity Rate		$0.575		
Total Gas Sales Service Rate		$0.704	$0.925	$0.815

Total High Load Factor Dollars

Projected Sales	Rate	Total Cost
11,467,640	$0.815	$9,346,127

Development of Gas Lighting Rate per CCF (100% Load Factor)

Description		Peak Day Cap. Method
Demand Rate	($25.46 / 365)	$0.070
Commodity Rate		$0.575
Total Gas Sales Service Rate		$0.645

Total Gas Cooling and Gas Lighting Dollars

Projected Sales	Rate	Total Cost
1,460	$0.645	$942

Development of RS1,RS2, GS, MVS, and LVS Rate per CCF

Description	Firm Gas Cost	Volume (CCF)	Rate per CCF	Margin Sharing Rate per CCF	Final Rate per CCF
Total System Gas Cost	$41,810,055	45,209,210			
Less : Allocated to HLFS & SFS	$9,346,127	11,467,640			
Less : Allocated to GL, GC	$942	1,460			
Total Remaining System	$32,462,986	33,740,110	$0.962	($0.012)	$0.950

Based on Total Firm Gas Costs Recoverable through GSR effective February 1, 2009

Description	Allocator	Total System Costs	Volume (Ccf)	Cost / Ccf
Fixed Gas Costs	Peak Day Capacity Entitlements	$13,876,297	476,336	$29.13
Variable Gas Costs	Annual Volume	$39,318,311	42,143,932	$0.933
Total Firm Gas Costs	Annual Volume	$53,194,609	42,143,932	$1.262

Development of High Load Factor Service Rate per CCF (65% Load Factor)

Description		Peak Day Cap. Method	System Average Cost	HLFS Average Rate
Demand Rate	($29.13 / 197)	$0.148		
Commodity Rate		$0.933		
Total Gas Sales Service Rate		$1.081	$1.262	$1.172

Total High Load Factor Dollars

Projected Sales	Rate	Total Cost
9,092,722	$1.172	$10,656,670

Development of Gas Lighting Rate per CCF (100% Load Factor)

Description		Peak Day Cap. Method
Demand Rate	($29.13 / 365)	$0.080
Commodity Rate		$0.933
Total Gas Sales Service Rate		$1.013

Total Gas Cooling and Gas Lighting Dollars

Projected Sales	Rate	Total Cost
1,550	$1.013	$1,570

Development of RS1, RS2, GS, MVS, and LVS Rate per CCF

Description	Firm Gas Cost	Volume (CCF)	Rate per CCF	Margin Sharing Rate per CCF	Final Rate per CCF
Total System Gas Cost	$53,194,609	42,143,932			
Less : Allocated to HLFS	$10,656,670	9,092,722			
Less : Allocated to GL, GC	$1,570	1,550			
Total Remaining System	$42,536,369	33,049,660	$1.287	($0.044)	$1.243

Change in Total Firm Gas Costs Recoverable through GSR

Description	Costs	Cost / Ccf
Fixed Gas Costs	$1,943,717	($3.670)
Variable Gas Costs	($13,328,271)	($0.358)
Total Firm Gas Costs	($11,384,554)	($0.337)

Change in HLFS and SFS Rate

Description	HLFS Cost / Ccf
Demand Rate	
Commodity Rate	
Total Gas Sales Service Rate	($0.357)

Change in GC & GL Rates

Description	GC & GL Cost / Ccf
Demand Rate	
Commodity Rate	
Total Gas Sales Service Rate	($0.368)

Change in RS, GS, MVS, and LVS Rates

Description	Rate per CCF	Margin Sharing Rate per CCF	Final Rate per CCF
Total System Gas Cost			
Less : Allocated to HLFS			
Less : Allocated to GL, GC			
Total Remaining System	($0.325)	$0.032	($0.293)

Schedule F
November 1, 2009

Chesapeake Utilities Corporation
Delaware Division
Firm Cost of Gas Comparison

Description	Projection Inherent In November 1, 2009 GSR Filing: Projected 12 Months Ending Oct-10	Average Cost Per MCF	12 Months Ending Oct-09	Average Cost Per MCF	12 Months Ended Oct-08	Average Cost Per MCF	12 Months Ended Oct-07	Average Cost Per MCF	12 Months Ended Oct-06	Average Cost Per MCF
Firm Fixed Gas Costs										
ESNG FT Reservation	$10,993,292	$2.4316	$10,240,917	$2.5193	$9,447,010	$2.7845	$8,964,292	$2.7216	$6,725,789	$2.1574
Upstream FT Reservation	$5,376,693	$1.1893	$4,432,276	$1.0904	$2,457,470	$0.7243	$2,462,733	$0.7477	$2,336,041	$0.7493
Storage Demand and Capacity	$1,043,397	$0.2308	$1,053,369	$0.2591	$1,084,329	$0.3196	$982,450	$0.2983	$979,521	$0.3142
Take-Or-Pay Surcharge	$0	$0.0000	$0	$0.0000	$0	$0.0000	$0	$0.0000	$0	$0.0000
Total Firm Fixed Gas Costs	**$17,413,382**	**$3.8517**	**$15,726,562**	**$3.8688**	**$12,988,809**	**$3.8284**	**$12,409,474**	**$3.7675**	**$10,041,351**	**$3.2209**
Firm Variable Gas Costs										
Upstream Commodity	$26,354,986	$5.8296	$29,058,004	$7.1483	$27,882,877	$8.2184	$26,083,564	$7.9190	$31,488,139	$10.1002
ESNG FT Commodity	$110,383	$0.0244	($12,022)	($0.0030)	($1,273)	($0.0004)	$19,332	$0.0059	$47,659	$0.0153
CNG for Vehicular Use	($927)	($0.0002)	($864)	($0.0002)	($744)	($0.0002)	($942)	($0.0003)	($1,121)	($0.0004)
Storage Injection/Withdrawal & Commodity	$3,718,078	$0.8224	$5,905,003	$1.4526	$4,101,229	$1.2088	$4,800,262	$1.4574	$4,951,108	$1.5881
Propane	$0	$0.0000	$21,029	$0.0052	$24,397	$0.0072	$37,697	$0.0114	$2,898	$0.0009
Total Firm Variable Gas Costs	**$30,182,520**	**$6.6762**	**$34,971,150**	**$8.6030**	**$32,006,486**	**$9.4338**	**$30,939,913**	**$9.3934**	**$36,488,883**	**$11.7041**
Total Firm Gas Costs	**$47,595,902**	**$10.5279**	**$50,697,712**	**$12.4718**	**$44,995,295**	**$13.2623**	**$43,349,387**	**$13.1609**	**$46,530,034**	**$14.9250**
Total Firm Mcf Sales	**4,520,921**		**4,064,995**		**3,392,729**		**3,293,793**		**3,117,586**	

Reconciliation of Total Firm Gas Costs (Schedule F) to Cost Recoverable through GSR (Schedule B):

Total Firm Gas Costs (Schedule F)	$47,595,902
Supplier Refunds (Schedule B)	($82,931)
Recovery of Under Collection from Transp.	$0
GSR Settlement Adjustment	$39,286
ESNG Capacity Release for Transportation	($1,401,759)
Balancing Rate Credit	($230,894)
(Over)/Under Collection (Schedule D.1)	($4,109,549)
Costs Recoverable through GSR	**$41,810,055**

Chesapeake Utilities Corporation
Delaware Division
Unaccounted For, Company Use & Pressure Compensation Gas Volumes
Twelve Months Ended July 31, 2009

	(1)	(2)	(3)	(4)	(5) *	(6)
Month	Total Receipts (Mcf)	Total Sales and Transportation (Mcf)	Unaccounted For, Pressure Compensation and Company Use (Mcf)	Company Use (Mcf)	Pressure Compensation (Mcf)	Unaccounted For Gas (Mcf)
August-08	176,352	162,530	13,822	97	2,427	11,298
September-08	198,619	187,205	11,414	74	2,796	8,544
October-08	331,543	253,323	78,220	27	3,784	74,409
November-08	552,856	392,422	160,434	110	5,861	154,463
December-08	753,232	709,635	43,597	346	10,599	32,652
January-09	1,009,326	853,854	155,472	428	12,753	142,291
February-09	719,679	817,570	(97,891)	399	12,211	(110,501)
March-09	655,986	712,639	(56,653)	333	10,644	(67,630)
April-09	397,314	482,045	(84,731)	135	7,200	(92,066)
May-09	261,657	287,904	(26,247)	45	4,300	(30,592)
June-09	219,063	222,568	(3,505)	57	3,324	(6,886)
July-09	208,140	212,349	(4,209)	45	3,172	(7,426)
Total	5,483,767	5,294,044	189,723	2,096	79,071	108,556

Unaccounted For and Company Use as % of Sales (Column 3 / Column 2)	3.58%
Unaccounted For as % of Receipts (Column 6 / Column 1)	1.98%

* Represents calculation to pressurize gas delivered from the ESNG transmission pipeline to a standard pressure.

Schedule H
November 1, 2009

Chesapeake Utilities Corporation
Delaware Division
Development of Gas Sales Service Rates Effective November 1, 2009
Balancing Rate Credit for Transportation Customers

Rate Class	Projected Nov-09	Projected Dec-09	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Total
Large Volume Service:													
Volumes - Mcf	21,198	35,244	35,924	31,481	28,339	20,355	9,202	7,284	15,279	14,581	24,024	28,045	270,956
Balancing Rate Revenue	$11,871	$19,737	$20,117	$17,629	$15,870	$11,399	$5,153	$4,079	$8,556	$8,165	$13,453	$15,705	$151,734
High Load Factor Service:													
Volumes - Mcf	77,082	96,125	86,091	80,455	91,233	92,569	81,047	83,294	76,562	76,019	76,207	103,111	1,019,795
Balancing Rate Revenue	$5,396	$6,729	$6,026	$5,632	$6,386	$6,480	$5,673	$5,831	$5,359	$5,321	$5,335	$7,218	$71,386
Interruptible Service:													
Volumes - Mcf	31,297	43,281	25,644	35,698	38,364	40,236	30,712	25,602	31,207	26,782	27,589	32,251	388,661
Balancing Rate Revenue	$626	$866	$513	$714	$767	$805	$614	$512	$624	$536	$552	$645	$7,774
Total Balancing Rate Revenue	$17,893	$27,332	$26,656	$23,975	$23,023	$18,684	$11,440	$10,422	$14,539	$14,022	$19,340	$23,568	$230,894

Chesapeake Utilities Corporation
Delaware Division
Capacity Release Credit Calculations
Development of Gas Sales Service Rates Effective November 1, 2009

	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total
Zone 1:													
Customer No. 1	281	281	281	281	281	281	281	281	281	281	281	281	
Customer No. 2	20	20	20	20	20	20	20	20	20	20	20	20	
Customer No. 3	87	87	87	87	87	87	87	87	87	78	78	78	
Customer No. 4	24	24	24	24	24	24	24	24	24	22	22	22	
Customer No. 5	53	53	53	53	53	53	53	53	53	53	53	53	
Customer No. 6	6	4	0	0	0	0	0	0	0	0	18	37	
Daily Nomination - DT	471	469	465	465	465	465	465	465	465	454	472	491	
Reservation FT - Zone 1	$9.0271	$9.0271	$9.0271	$9.0271	$9.0271	$9.0271	$9.0271	$9.0271	$9.0271	$9.0271	$9.0271	$9.0271	
Capacity Release Credit	$4,251.76	$4,233.71	$4,197.60	$4,197.60	$4,197.60	$4,197.60	$4,197.60	$4,197.60	$4,197.60	$4,098.30	$4,260.79	$4,432.31	$50,660.07
Zone 2:													
Customer No. 7	35	35	35	35	35	35	35	35	35	35	35	35	
Customer No. 8	0	0	0	0	0	0	0	0	0	0	235	152	
Customer No. 9	143	143	143	143	143	143	143	143	143	143	143	143	
Customer No. 10	83	83	83	83	83	83	83	83	83	83	83	83	
Customer No. 11	53	53	53	53	53	53	53	53	53	53	53	53	
Customer No. 12	201	201	208	208	208	208	208	208	208	208	208	208	
Customer No. 13	35	35	35	35	35	35	35	35	35	35	35	35	
Customer No. 14	23	28	28	28	28	0	0	0	0	0	0	0	
Customer No. 15	34	36	31	29	26	23	21	32	28	22	50	50	
Customer No. 16	130	130	130	130	130	130	130	130	130	130	130	130	
Customer No. 17	167	192	192	192	192	192	192	192	192	192	192	192	
Customer No. 18	344	344	344	344	344	344	344	344	344	344	344	344	
Customer No. 19	12	12	12	12	12	12	12	12	12	12	12	12	
Customer No. 20	76	76	76	76	76	76	76	76	76	76	76	76	
Customer No. 21	143	143	143	143	143	143	143	143	143	143	143	143	
Customer No. 22	25	25	25	25	25	25	25	25	25	25	25	25	
Customer No. 23	59	54	54	54	54	54	54	54	54	54	54	54	
Customer No. 24	19	27	27	27	27	27	27	27	27	27	27	27	
Customer No. 25	31	21	21	21	21	21	21	21	21	21	21	21	
Customer No. 26	39	27	27	27	27	27	27	27	27	27	27	27	
Customer No. 27	171	171	171	171	171	171	171	171	171	171	171	171	
Customer No. 28	18	18	18	18	18	18	18	18	18	18	18	18	
Customer No. 29	10	10	10	10	10	10	10	10	10	10	10	10	
Customer No. 30	12	12	12	12	12	12	12	12	12	12	12	12	
Customer No. 31	16	16	16	16	16	16	16	16	16	16	16	16	
Customer No. 32	30	30	30	30	30	30	30	30	30	30	30	30	
Customer No. 33	11	23	15	25	22	11	3	34	34	34	34	34	
Customer No. 34	10	10	10	11	11	11	11	11	11	11	11	11	
Customer No. 35	41	41	41	41	41	41	41	41	41	41	41	41	
Customer No. 36	19	19	19	19	19	19	19	19	19	19	19	19	
Customer No. 37	54	50	50	50	50	50	50	50	50	50	50	50	
Customer No. 38	13	13	13	13	13	13	13	13	13	13	13	13	
Customer No. 39	10	10	10	10	10	10	10	10	10	10	12	12	
Customer No. 40	1	1	1	1	1	1	1	1	1	1	1	1	
Customer No. 41	2	2	2	2	2	2	2	2	2	2	2	2	
Customer No. 42	1	1	1	1	1	1	1	1	1	1	2	2	
Customer No. 43	1	1	1	1	1	1	1	1	1	1	4	4	
Customer No. 44	1	1	1	1	1	1	1	1	1	1	2	2	
Customer No. 45	2	2	2	2	2	2	2	2	2	2	19	19	
Customer No. 46	6	6	6	6	6	6	6	6	6	6	6	6	
Customer No. 47	4	4	4	4	4	4	4	4	4	4	3	3	
Customer No. 48	0	0	0	0	0	0	303	303	303	303	303	303	
Customer No. 49	2	0	0	0	0	0	0	0	0	0	2	2	
Customer No. 50	63	61	61	89	71	140	87	97	123	161	133	113	
Customer No. 51	42	42	42	42	42	42	42	42	42	42	42	42	
Customer No. 52	256	256	256	256	256	256	256	256	256	256	256	256	

Customer No. 53	464	464	464	464	464	464	464	464	464	464	464	330	
Customer No. 54	21	21	13	13	13	13	13	13	13	13	13	13	
Customer No. 55	18	18	12	12	12	12	12	12	12	12	12	12	
Customer No. 56	745	745	745	745	745	745	744	744	744	744	744	744	
Customer No. 57	15	15	15	15	15	15	15	15	15	15	15	15	
Customer No. 58	16	16	16	16	16	16	16	16	16	16	16	16	
Customer No. 59	133	160	160	160	160	160	160	160	160	160	160	160	
Customer No. 60	3	3	3	3	3	3	3	3	3	3	3	3	
Customer No. 61	9	8	8	8	8	8	8	8	8	8	8	8	
Customer No. 62	164	204	138	195	180	227	392	326	333	233	203	203	
Customer No. 63	159	154	154	170	154	159	154	159	154	154	281	272	
Customer No. 64	211	125	121	92	102	92	125	247	190	213	213	65	
Customer No. 65	974	1,154	1,251	1,411	1,016	799	485	204	307	271	262	365	
Customer No. 66	77	77	77	77	77	77	77	77	77	77	77	162	
Customer No. 67	129	129	129	129	129	129	129	129	129	129	129	126	
Customer No. 68	139	139	139	139	139	139	139	139	139	139	139	189	
Daily Nomination - DT	5,725	5,897	5,904	6,145	5,705	5,557	5,675	5,507	5,577	5,496	5,844	5,685	
Reservation FT - Zone 2	$17.3339	$17.3339	$17.3339	$17.3339	$17.3339	$17.3339	$17.3339	$17.3339	$17.3339	$17.3339	$17.3339	$17.3339	
Capacity Release Credit	$99,236.58	$102,218.01	$102,339.35	$106,516.82	$98,889.90	$96,324.48	$98,369.88	$95,457.79	$96,671.16	$95,267.11	$101,299.31	$98,543.22	$1,191,133.61
Other:													
Customer No. 69	77,340	79,918	79,918	72,184	79,918	77,340	79,918	77,340	79,918	79,918	77,340	79,918	
Volumetric Release Credit	$13,147.80	$13,586.06	$13,586.06	$12,271.28	$13,586.06	$13,147.80	$13,586.06	$13,147.80	$13,586.06	$13,586.06	$13,147.80	$13,586.06	$159,964.90
Total Capacity Release Credit	$116,636.14	$120,037.78	$120,123.01	$122,985.70	$116,673.56	$113,669.88	$116,153.54	$112,803.19	$114,454.82	$112,951.47	$118,707.90	$116,561.59	$1,401,758.58

Chesapeake Utilities Corporation
Delaware Division
Cost of Fixed and Variable Gas Supply Resources
Based on November 1, 2009 Gas Costs
Transportation Balancing Services

Description	Monthly Demand in DT	Annual Demand in DT	Average Monthly Rate / DT	Average Annual Rate / DT	Current Annualized Gas Cost
Storage Demand					
Columbia					
FSS (includes assoc. SST)	8,224	98,688	$5.8929	$70.7144	$581,555
Transco					
GSS	2,655	31,860	$3.0027	$36.0326	$95,667
LSS	580	6,960	$4.6354	$55.6247	$32,262
LGA	911	10,932	$1.3552	$16.2627	$14,815
WSS (includes assoc. FT)	1,680	20,160	$6.6721	$80.0651	$134,509
ESS (includes assoc. FT)	4,727	56,724	$10.1634	$121.9606	$576,508
PS Reservation	274	3,288	$8.9063	$106.8757	$29,284
Fuel Retention (0.0%)	0	0			
ESNG Reservation					
MDTQ 365 Day (GSS, ESS)	4,727	56,724	$18.2318	$218.7810	$1,034,178
MDTQ 181 Day (FSS)	8,224	49,344	$14.8421	$89.0524	$732,367
MDTQ 151 Day (LSS, WSS)	2,260	11,300	$14.8419	$74.2093	$167,713
MDTQ 90 Day (LGA, PS)	1,185	3,555	$26.5778	$79.7333	$94,484
Storage Demand	19,051	228,612	$15.2807	$183.3679	$3,493,342
Storage Capacity					
Columbia					
FSS	472,250	5,667,000	$0.0289	$0.3468	$163,776
Transco					
GSS	131,370	1,576,440	$0.0167	$0.2007	$26,371
LSS	29,000	348,000	$0.0183	$0.2190	$6,351
WSS	142,830	1,713,960	$0.0073	$0.0876	$12,512
ESS	47,262	567,144	$0.0438	$0.5256	$24,842
LGA	5,708	68,496	$0.2609	$3.1314	$17,874
Storage Capacity	828,420	9,941,040	$0.0253	$0.3039	$251,726
Storage Demand & Capacity					
Columbia					
FSS	8,224	98,688	$7.5524	$90.6288	$745,331
Transco					
GSS	2,655	31,860	$3.8304	$45.9652	$122,038
LSS	580	6,960	$5.5479	$66.5747	$38,613
LGA	911	10,932	$2.9902	$35.8829	$32,689
WSS	1,680	20,160	$7.2927	$87.5127	$147,021
ESS	4,727	56,724	$10.6013	$127.2160	$601,350
PS Reservation	274	3,288	$8.9063	$106.8757	$29,284
Fuel Retention (0.0%)	0	0			
ESNG Reservation					
MDTQ 365 Day (GSS, ESS)	4,727	56,724	$18.2318	$218.7810	$1,034,178
MDTQ 181 Day (FSS)	8,224	49,344	$14.8421	$89.0524	$732,367
MDTQ 151 Day (LSS, WSS)	2,260	11,300	$14.8419	$74.2093	$167,713
MDTQ 90 Day (LGA, PS)	1,185	3,555	$26.5778	$79.7333	$94,484
Storage Demand & Capacity	19,051	228,612	$16.3818	$196.5812	$3,745,068
Propane Peak Shaving	12,048	n/a	n/a	$0.00	$0
Fixed Gas Supply Resources	31,099			**$120.4241**	$3,745,068

Storage Injection & Withdrawal					
GSS	262,740	n/a	$0.0420	n/a	$11,022
LSS	58,000	n/a	$0.0236	n/a	$1,371
LGA	11,416	n/a	$1.3690	n/a	$15,629
WSS	285,660	n/a	$0.0129	n/a	$3,699
ESS	94,524	n/a	$0.0251	n/a	$2,368
FSS	944,500	n/a	$0.0153	n/a	$14,451
Variable Gas Supply Resources	1,656,840	n/a	$0.0293	n/a	$48,540
Half of Variable Rate For Either Injection or Withdrawal			**$0.0147**		

Chesapeake Utilities Corporation
Delaware Division
Transportation Balancing Services
Development of Firm Balancing Service Rate
Large Volume Service

Fixed Gas Supply Cost	Annual Load Factor	Average Daily Load	Cost Per Gas Supply Entitlement	Average Cost per DT	Average Cost 45.25% Design Day
@ Load Factor of	10%	37	$120.4241	$3.2547	$1.4728
@ Load Factor of	20%	73	$120.4241	$1.6496	$0.7464
@ Load Factor of	30%	110	$120.4241	$1.0948	$0.4954
@ Load Factor of	40%	146	$120.4241	$0.8248	$0.3732
@ Load Factor of	50%	183	$120.4241	$0.6581	$0.2978
@ Load Factor of	60%	219	$120.4241	$0.5499	$0.2488
@ Load Factor of	70%	256	$120.4241	$0.4704	$0.2129
@ Load Factor of	80%	292	$120.4241	$0.4124	$0.1866
@ Load Factor of	90%	329	$120.4241	$0.3660	$0.1656
@ Load Factor of	100%	365	$120.4241	$0.3299	$0.1493
Del. Div. Weighted Average	**28.03%**	**102**	**$120.4241**	**$1.1806**	**$0.5342**

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			**$0.0147**	**24.91%**	**$0.0037**

Development of Firm Balancing Service Rate		
Fixed Capacity Rate per DT	**$0.5342**	
Variable Commodity Rate per DT	**$0.0037**	
Total Firm Balancing Service Rate per DT	**$0.5379**	
Total Firm Balancing Service Rate per Mcf	**$0.5567**	
Total Firm Balancing Service Rate per Ccf	**$0.056**	

Chesapeake Utilities Corporation
Delaware Division
Transportation Balancing Services
Development of Firm Balancing Service Rate
High Load Factor Service

Fixed Gas Supply Cost	Annual Load Factor	Average Daily Load	Cost Per Gas Supply Entitlement	Average Cost per DT	Average Cost 16.05% Design Day
@ Load Factor of	10%	37	$120.4241	$3.2547	$0.5224
@ Load Factor of	20%	73	$120.4241	$1.6496	$0.2648
@ Load Factor of	30%	110	$120.4241	$1.0948	$0.1757
@ Load Factor of	40%	146	$120.4241	$0.8248	$0.1324
@ Load Factor of	50%	183	$120.4241	$0.6581	$0.1056
@ Load Factor of	60%	219	$120.4241	$0.5499	$0.0883
@ Load Factor of	70%	256	$120.4241	$0.4704	$0.0755
@ Load Factor of	80%	292	$120.4241	$0.4124	$0.0662
@ Load Factor of	90%	329	$120.4241	$0.3660	$0.0587
@ Load Factor of	100%	365	$120.4241	$0.3299	$0.0529
Del. Div. Weighted Average	**74.16%**	**271**	**$120.4241**	**$0.4444**	**$0.0713**

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			$0.0147	3.42%	$0.0005

Development of Firm Balancing Service Rate		
Fixed Capacity Rate per DT	$0.0713	
Variable Commodity Rate per DT	$0.0005	
Total Firm Balancing Service Rate per DT	$0.0718	
Total Firm Balancing Service Rate per Mcf	$0.0743	
Total Firm Balancing Service Rate per Ccf	$0.007	

Chesapeake Utilities Corporation
Delaware Division
Transportation Balancing Services
Development of Interruptible Balancing Service Rate
Interruptible Transportation Service

Fixed Gas Supply Cost	Annual Load Factor	Average Daily Load	Cost Per Gas Supply Entitlement	Average Cost per DT	Average Cost @ Use of 6.58%
@ Load Factor of	10%	37	$120.4241	$3.2547	
@ Load Factor of	20%	73	$120.4241	$1.6496	
@ Load Factor of	30%	110	$120.4241	$1.0948	
@ Load Factor of	40%	146	$120.4241	$0.8248	
@ Load Factor of	50%	183	$120.4241	$0.6581	
@ Load Factor of	60%	219	$120.4241	$0.5499	
@ Load Factor of	70%	256	$120.4241	$0.4704	
@ Load Factor of	80%	292	$120.4241	$0.4124	
@ Load Factor of	90%	329	$120.4241	$0.3660	
@ Load Factor of	100%	365	$120.4241	$0.3299	
Interruptible @ 100% LFR	**100.00%**	**365**	**$120.4241**	**$0.3299**	**$0.0217**

Variable Gas Supply Cost			Average Cost per DT	Estimated Imbalance Percentage	Variable Cost per DT
Variable Commodity Rate			**$0.0147**	**6.58%**	**$0.0010**

Development of Interruptible Balancing Service Rate		
Fixed Capacity Rate per DT	**$0.0217**	
Variable Commodity Rate per DT	**$0.0010**	
Total Balancing Service Rate per DT	**$0.0227**	
Total Balancing Service Rate per Mcf	**$0.0235**	
Total Balancing Service Rate per Ccf	**$0.002**	

Chesapeake Utilities Corporation
Delaware Division
Gas Supply Resources
Demand and Capacity Entitlements effective November 2008 & November 2009
(DT)

Transcontinental Gas Pipeline Corporation			
		2008	2009
FT, MDQ	+	21,045	21,112
PS-1 FT, MDQ	+	311	311
GSS, MDQ	+	2,655	2,655
LSS, MDQ	+	580	580
LGA, MDQ	+	911	911
GSS, Capacity		131,370	131,370
LSS, Capacity		29,000	29,000
LGA, Capacity		5,708	5,708
WSS, Demand		1,680	1,680
WSS, Capacity		142,830	142,830
ESS, Demand		1,788	4,727
ESS, Capacity		17,967	47,262
EESWS, Demand		2,941	18
EESWS, Capacity		29,295	176
Columbia Gulf Transmission Company			
		2008	2009
FTS-1, MDQ, Nov - Mar		880	880
FTS-1, MDQ, Apr - Oct		809	809
Columbia Gas Transmission Corporation			
		2008	2009
FTS, MDQ	+	3,460	18,460 *
SST, MDQ, Oct - Mar		8,224	8,224
SST, MDQ, Apr - Sep		4,113	4,113
FSS, MDQ	+	8,224	8,224
FSS, Capacity		472,250	472,250
Max Daily Upstream Entitlement	=	37,186	52,253
Eastern Shore Natural Gas Company			
		2008	2009
FT, MDQ		56,556	60,623
ST, MDQ		5,081	5,081
Total		61,637	65,704
Chesapeake Utilities Corporation - Delaware Division			
		2008	2009
Propane Peak Shaving Facilities		12,048	12,048

MDQ = Maximum Daily Quantity

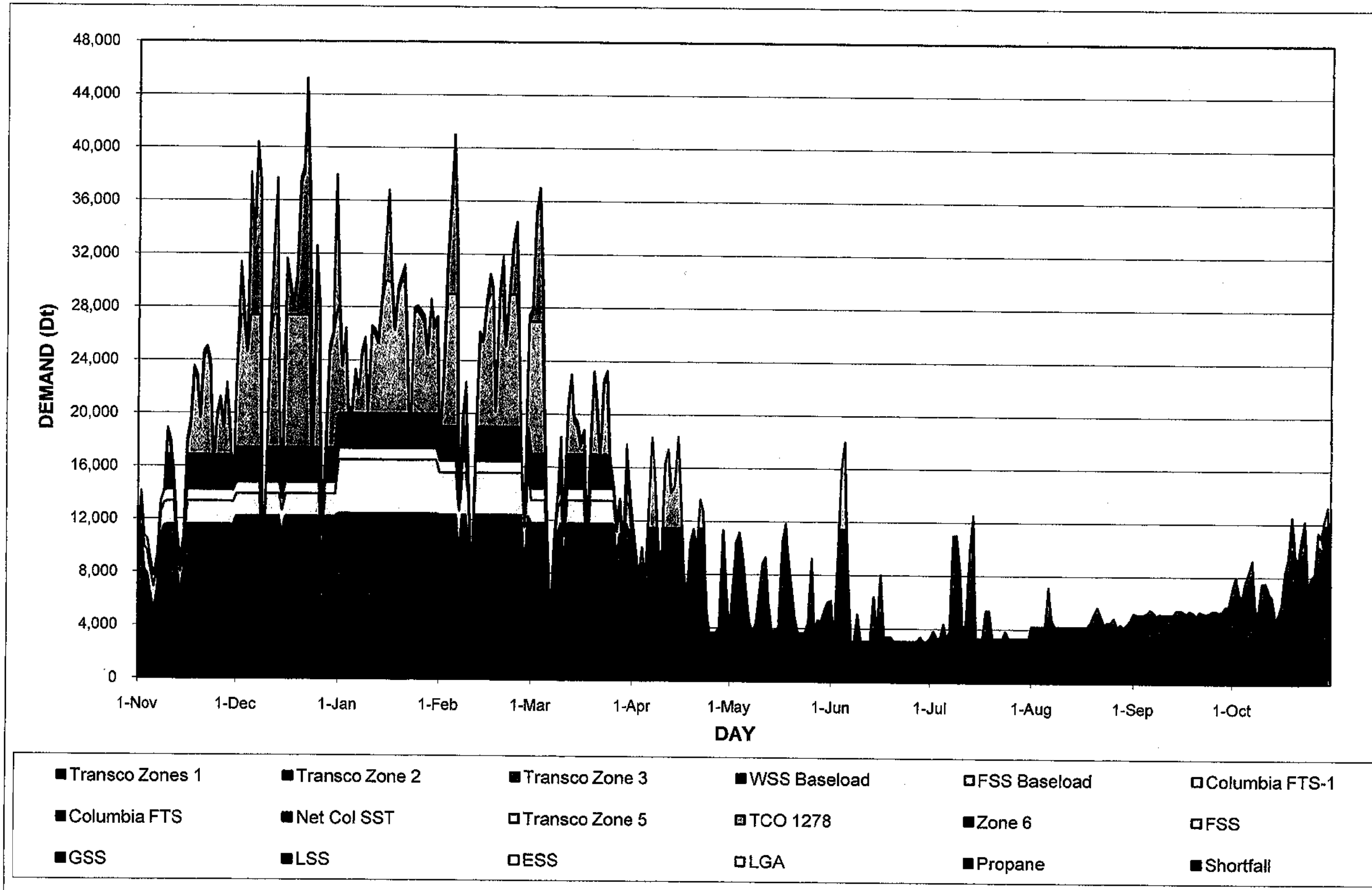
* The FTS, MDQ for Columbia includes an additional 7,500 Dts to be placed into service on Nov. 15, 2009 and for which a precedent agreement is pending.

Schedule M
November 1, 2009

DELAWARE DIVISION LOAD AND SUPPLY

2009 - 2010 Forecast Year
CHART

Weather Year Used: **10-YR Avg**



EASTERN SHORE

June 27, 2006

Ms. Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Eastern Shore Natural Gas Company
Docket No. RP06- -000
Petition for Approval of Settlement Agreement

Dear Ms. Salas:

Pursuant to Rule 207(a)(5) of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. § 385.207(a)(5) (2005), Eastern Shore Natural Gas Company ("Eastern Shore") hereby submits for filing an original and fourteen copies of the attached "Petition for Approval of Settlement Agreement" ("Petition").

Eastern Shore is filing the attached Petition to implement a rate-related settlement agreement ("Settlement Agreement"). The attached Settlement Agreement is not opposed by any of Eastern Shore's firm transportation customers. The Settlement Agreement is the result of collaborative discussions between Eastern Shore and its customers. Approval of the Settlement Agreement will provide Eastern Shore and its shippers utilizing Eastern Shore's system with benefits described in the attached Petition, including but not limited to the following: (1) advancement of a necessary infrastructure project to meet the growing demand for natural gas on the Delmarva Peninsula; (2) sharing of project development costs by the participating shippers in the project; and (3) no development cost risk for non-participating shippers. Eastern Shore submits that the uncontested Settlement Agreement provides for a fair and equitable resolution of the issues confronted by Eastern Shore and its customers, and that it does so in a timely and efficient manner.

The Commission encourages pipelines and their customers to resolve differences over rates before making any filing with the Commission, because it enables the quick processing of a settlement for the benefits of a pipeline's customers, without the expense of a hearing and lengthy litigation. The Commission has also provided the public with guidance on procedures for implementing a rate-related settlement that is negotiated outside the context of an existing Commission proceeding. The Commission stated that a pipeline should file a petition for approval of the settlement agreement, along with *pro forma* tariff sheets showing how the agreement would be implemented, pursuant to Rule 207(a)(5) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.207(a)(5) (2005).

Appendix A to the Settlement Agreement contains a draft Commission letter order approving the Settlement Agreement, and an electronic version of this draft letter order in Microsoft Word format is included herewith on a 3-inch diskette. Eastern Shore is serving copies of this letter and all attachments upon all affected customers of Eastern Shore and interested state commissions. As reflected in the draft Commission notice of the Petition, Eastern Shore respectfully requests that the Commission set July 5, 2006 as the deadline for interventions, comments, and protests. This shortened comment period is appropriate given Eastern Shore's communications regarding the settlement issues with all firm customers on the Eastern Shore system. In addition, Eastern Shore respectfully requests that the Commission issue its order approving the uncontested Settlement Agreement as proposed herein by July 31, 2006.

Respectfully submitted,

Elaine B. Bittner
Vice President

Attachments

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Eastern Shore Natural Gas Company) Docket No. RP06- -000

**PETITION OF EASTERN SHORE NATURAL GAS COMPANY
FOR APPROVAL OF SETTLEMENT AGREEMENT**

I.
INTRODUCTION

Pursuant to Rule 207(a)(5) of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure,[1] Eastern Shore Natural Gas Company ("Eastern Shore") hereby petitions the Commission for approval of the attached uncontested settlement agreement, including associated *pro forma* tariff sheets, submitted herewith ("Settlement Agreement"). In support hereof, Eastern Shore states as follows:

II.
CORRESPONDENCE AND COMMUNICATION

All correspondence and communications regarding this filing should be addressed to the following:

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* Parties to be designated on the Commission's official service list.

[1] 18 C.F.R. § 385.207(a)(5) (2005). Under Rule 602(c)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R § 602(c)(2), an offer of settlement includes an "explanatory statement." Because this petition provides the substantive information normally included in an explanatory statement, Eastern Shore respectfully submits that the inclusion of a separate explanatory statement would be unnecessarily duplicative in the context of this "Rule 207(a)(5) Settlement."

III.
BACKGROUND

Eastern Shore has operated interstate natural gas transmission facilities on the Delmarva Peninsula since 1959. Eastern Shore provides firm and interruptible transportation service to several local distribution companies ("LDCs"), as well as industrial and power generation customers with operations on the Delmarva Peninsula. Eastern Shore also provides firm storage service to several of its LDC customers. Currently, all of the gas transported by Eastern Shore is received from Transcontinental Gas Pipe Line Corporation ("Transco") and Columbia Gas Transmission Corporation ("Columbia") at points of interconnection with those pipelines in Southeastern Pennsylvania and Northern Delaware, all upstream of Eastern Shore's customers on the Peninsula.

Over the years, Eastern Shore has expanded its pipeline system to meet the growing needs of its customers on the Peninsula. Over the past ten years alone, responding to the significant population growth that has occurred on the Peninsula and the related demand for natural gas as the fuel of choice, Eastern Shore has more than doubled its natural gas transmission capacity on the Peninsula by looping its two main north-south pipelines, adding compression facilities, and extending its mainline to areas which previously had no access to natural gas. To meet future needs for additional pipeline transportation capacity, however, Eastern Shore and its customers firmly believe that it must supplement its existing supply sources by constructing new pipeline infrastructure that would extend from Dominion Resources' liquefied natural gas ("LNG") facilities located at Cove Point, Maryland, cross under the Chesapeake Bay and interconnect with Eastern Shore's existing pipeline system ("Project"). This Project would provide the necessary infrastructure that would provide Eastern Shore's customers access to a new source of supply and would reduce their total dependence on Transco and Columbia as the sole current sources of supply and upstream capacity for transportation to Eastern Shore's system. Moreover, by constructing new pipeline infrastructure that would connect with its existing main pipelines about midway down the Delmarva Peninsula, Eastern Shore would: (1) greatly enhance operational flexibility on its system; (2) greatly strengthen and expand its ability to meets its customers' demands on both the northern and southern halves of its system; and (3) provide the opportunity for low cost future expansion on its system.

The costs of licensing, permitting, and constructing the Project will be far greater than any of Eastern Shore's prior expansion projects. To justify such a large investment, Eastern Shore needs long-term, firm commitments from customers sufficient to make the project economical. Eastern Shore has been surveying customer interest in such capacity in open seasons conducted over the past few years to measure its customers' needs for additional capacity. Two of its longstanding LDC customers, Chesapeake Utilities Corporation ("CUC") and Delmarva Power & Light Company ("DPL"), have signed binding Precedent Agreements subscribing to a total of 60,000 dekatherms per day ("dts") of firm service capacity on the Project. Such precedent agreements specify negotiated rates and twenty-year terms. In addition, pursuant to Letter Agreements that are an integral part of their Precedent Agreements, CUC and DPL have each agreed to pay a proportionate share of certain pre-certification costs incurred by Eastern Shore in the event that the Project is not certificated and placed in service.

In such event, CUC and DPL will pay their proportionate shares of pre-certification costs by means of a rate reflecting an amortization of such costs over a period of no less than 20 years. Such Letter Agreements further provide that this negotiated arrangement will be submitted to the Commission as a pre-filed settlement, supported or not opposed by Eastern Shore's firm service customers, for approval by the Commission. Finally, the Letter Agreements provide that, if the Project is completed and placed in service, the Letter Agreements will become null and void.

IV.
PETITION FOR APPROVAL

The Commission has recognized the benefits of granting pipelines and shippers the flexibility to resolve rate-related issues outside the traditional format of an expensive, time-consuming, and contentious rate case.[2] Accordingly, the Commission last year provided the industry with additional guidance on procedures for implementing a rate-related settlement negotiated outside the context of an existing proceeding.[3] Specifically, the Commission provided that a pipeline could file a petition for approval of a settlement agreement, along with *pro forma* tariff sheets showing how the agreement would be implemented, pursuant to Rule 207(a)(5) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.207(a)(5) (2005).[4]

In accordance with the Commission's guidance in the *DTI Order,* Eastern Shore is filing this petition for Commission approval of the Settlement Agreement. Eastern Shore submits that the Settlement Agreement is in the public interest and should be approved without

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2 See Dominion Transmission, Inc., 111 FERC ¶ 61,285, at paragraph 30 (2005) ("DTI Order") (encouraging Pipelines and shippers to resolve rate-related issues outside of formal Commission proceedings); Algonquin Gas Transmission. LLC, 111 FERC ¶ 61,003, at paragraph 11 (2005); see also, *East Tennessee Natural Gas LLC,* 113 FERC ¶ 61,099 (2005); *Guardian Pipeline LLC,* 114 FERC ¶ 61,112 (2006).

3 DTI Order, 111 FERC ¶ 61,285, at P 32. See also AGT Order, 111 FERC ¶61,003, at paragraphs 11-15 (reviewing the negotiated rate agreements filed by pipeline).

4 DTI Order, 111 FERC ¶ 61,285, at paragraph 32. Id.

modification or condition. Approval of the Settlement Agreement will provide Eastern Shore and shippers utilizing Eastern Shore's system with the benefits discussed herein and in the Settlement Agreement, including the following:

- *Advancement of the Project.* The Settlement Agreement provides a method for sharing, among Eastern Shore, CUC, DPL, and other shippers on Eastern Shore's system who may subscribe to Project capacity ("Participating Shippers"), certain pre-certification costs in the event that the Project is not certificated and placed in service. Realization of the benefits of the Project for all of Eastern Shore's customers, described in the "Background" section above, will be advanced by approval of this risk-sharing agreement.

- *Sharing of Project Development Cost Risk.* The development cost risk-sharing embodied in the Settlement Agreement would apportion by prior agreement the pre-certification cost risk in the event that the Project is not certificated and placed in service. Approval of the Settlement Agreement will provide Eastern Shore assurance, prior to incurring large amounts of development costs, that the risk-sharing method embodied in the Settlement Agreement is acceptable to the Commission.

- *20-Year Amortization of Project Development Cost Risk.* The Settlement Agreement provides that a Participating Shipper's share of any pre-certification costs that may be incurred in the event that the Project is not certificated and placed in service would be amortized and collected over twenty years by means of a surcharge to the Participating Shipper. This 20-year amortization will greatly reduce the impact of any development cost sharing by a Participating Shipper.

- *No Development Cost Risk for Non-participating Shippers.* The Settlement Agreement provides that only Participating Shippers will be subject to a pre-certification cost surcharge in the event that the Project is not certificated and placed in service. The Settlement Agreement further provides that Eastern Shore will not seek to recover such costs from any other shipper on its system in any other Commission proceeding instituted following approval of the Settlement Agreement.

The terms and conditions of the settlement reflect an overall balancing of the various competing interests on the Eastern Shore system. As noted above, if the Project proceeds to completion, the Settlement Agreement will become null and void, and the development cost surcharge will not be necessary.

IV.

CONCLUSION

WHEREFORE, for the foregoing reasons, Eastern Shore respectfully requests that the Commission grant this petition and approve the Settlement Agreement, without condition or modification. In addition, Eastern Shore requests that the Commission grant any other authorizations or waivers that may be necessary to approve the uncontested Settlement Agreement as proposed herein.

Respectfully submitted,

Elaine B. Bittner
Vice President
Eastern Shore Natural Gas Company
417 Bank Lane
Dover, Delaware 19904
Phone: (302) 734-6710, Ext. 6016
Email: EBittner@chpk.com

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Eastern Shore Natural Gas Company) Docket No. RP06- -000

Notice of Petition for Approval of Settlement Agreement

Take notice that on June 27, 2006, pursuant to Rule 207(a)(5) of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedures, 18 C.F.R. § 385.207(a)(5) (2005), Eastern Shore Natural Gas Company ("Eastern Shore") tendered for filing a "Petition for Approval of Settlement Agreement," including a proposed settlement agreement and associated *pro forma* tariff sheets.

Eastern Shore states that the purpose of this filing is to implement a pre-filed settlement in accordance with the procedures set forth in *Dominion Transmission, Inc.*, 111 FERC ¶ 61,285 (2005). According to Eastern Shore, implementation of the Settlement Agreement will result in a number of benefits for shippers on the Delmarva Peninsula, all as more fully described in Eastern Shore's Petition. Eastern Shore further states that the proposed settlement agreement is supported or not opposed by all of its firm service customers.

Eastern Shore states that copies of its filing have been served upon all affected customers of Eastern Shore and interested state commissions.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Anyone filing an intervention or protest must serve a copy of that document on the Applicant. Anyone filing an intervention or protest on or before the intervention or protest date need not serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any

FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 p.m. Eastern Time on July 5, 2006.

Magalie R. Salas
Secretary

200606275100 Received FERC OSEC 06/27/2006 05:23:00 PM Docket# RP06-404-000

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Eastern Shore Natural Gas Company	)))	Docket No. RP06- -000

SETTLEMENT AGREEMENT

June 27, 2006

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Eastern Shore Natural Gas Company	)))	Docket No. RP06- -000

STIPULATION AND AGREEMENT

Pursuant to Rule 207(a)(5) of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. § 385.207(a)(5) (2005), Eastern Shore Natural Gas Company ("Eastern Shore") submits this Stipulation and Agreement ("S&A"), which provides a rate-related method for sharing the development cost risk for the Project described in the Petition for Approval of the Settlement Agreement filed in the instant proceeding. This S&A is comprehensive, resolving all issues with respect to the matters discussed herein and in the accompanying Petition for Approval of the Settlement Agreement. The entities listed in Appendix B hereto have stated that they support or do not oppose this S&A.

ARTICLE I
ISSUES RESOLVED

This S&A resolves all issues relating to an agreement to share 0project development costs for the Project, as detailed in Article II below and the *pro forma* tariff sheets contained in Appendix C hereof.

ARTICLE II
RATE SHEETS

1. Within seven (7) business days of the Approval Date of this S&A, Eastern Shore shall file with the Commission tariff sheets that are substantively identical to the *pro forma* tariff sheets contained in Appendix C, to be effective on the Effective Date, as defined in Article III below.

2. The *pro forma* tariff sheets contained in Appendix C shall specifically provide for the following:

(i) a formula for sharing Pre-Certification Costs incurred by Eastern Shore in the event that the Project is not certificated by the Commission and placed in service;

(ii) a contingent Pre-Certification Cost surcharge, based on the sharing formula, which would be collected over a 20-year period from Participating Shippers, as defined in the *pro forma* tariff sheets; and

(iii) assurance that Eastern Shore will at no time seek to impose such a surcharge on non-participating shippers.

3. Upon the Effective Date of this S&A, the Commission order approving this S&A shall constitute a determination that the Pre-Certification Cost Surcharge set forth in the *pro forma* tariff sheets is proper and adequate within the meaning of Section 4 of the Natural Gas Act.

4. Except as provided in the *pro forma* tariff sheets contained in Appendix C and any tariff sheets that may be necessary to implement the provisions of Article IV of this S&A, no further modification to Eastern Shore's tariff and no additional filing with the Commission shall be necessary to implement this S&A.

ARTICLE III
EFFECTIVE DATE

The "Effective Date" of this S&A is the date upon which the Commission approves this S&A by an order that (a) does not subject the S&A to modification or condition and (b) is no longer subject to rehearing or appeal. Upon written notice to the Commission, Eastern Shore may waive condition (a) or (b) specified in the preceding sentence, or both, in which case the Approval Date shall be the date specified in Eastern Shore's written notice to the Commission. Within ten (10) days of the issuance of a Commission order approving this S&A, Eastern Shore shall inform all other persons by written notice of any Commission-imposed condition or modification that Eastern Shore will not waive pursuant to this Article III.

ARTICLE IV
RESERVATIONS

1. Commission approval of this S&A constitutes a Commission determination that this S&A meets any requirements of the Commission's regulations, or approval of appropriate waivers, as may be necessary to effectuate all provisions of this S&A, including waiver of Section 154.207 of the Commission's regulations, 18 C.F.R. § 154.207 (2005), to the extent necessary to make the tariff sheets filed pursuant to Article II.1 of this S&A effective as of the Effective Date of this S&A.

2. All persons agree that, unless this S&A becomes effective as provided herein, this S&A and any and all discussions related hereto shall be privileged and shall not be admissible in evidence or in any way used, described or discussed in this or any other proceeding.

3. It is specifically understood and agreed that this S&A represents a negotiated settlement of the issues identified in Article I, resolved in a manner that is in the public interest, and that the benefits accruing to the persons hereto represent compromises by each person so that a balance could be achieved among competing interests.

4. All persons further understand and agree that the provisions of this S&A relate only to the specific matters referred to in this S&A, and no person waives any claim or right that it otherwise may have with respect to any matters not expressly provided for in this S&A. Nothing in this S&A shall preclude Eastern Shore from filing changes in its FERC Gas Tariff that are consistent with its specific obligations under this S&A, or preclude any person from responding thereto.

5. This S&A shall be binding on and shall inure to the benefit of the successors, assigns, or purchasers for value of the stock or assets, of Eastern Shore and all Participating Shippers.

Respectfully submitted,

Elaine B. Bittner
Vice President
Eastern Shore Natural Gas Company
417 Bank Lane
Dover, Delaware 19904
Phone: (302) 734-6710, Ext. 6016
Email: EBittner@chpk.com

June 27, 2006

Eastern Shore Natural Gas Company
Docket No. RP06-___-000

APPENDIX A

___ FERC ¶ _____
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

In re:
Docket No. RP06- -000
Issued: ____________, 2006

Elaine B. Bittner
Vice President
Eastern Shore Natural Gas Company
417 Bank Lane
Dover, Delaware 19904

Reference: June 27, 2006 Settlement Agreement

Dear Ms. Bittner:

1. On June 27, 2006, pursuant to Rule 207(a)(5) of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice Procedure, 18 C.F.R. § 385.207(a)(5) (2005), Eastern Shore Natural Gas Company ("Eastern Shore") filed a Petition for Approval of Settlement Agreement ("Petition").

2. In accordance with the Commission's guidance on the filing of settlement agreements in *Dominion Transmission, Inc.*, 111 FERC ¶ 61,285 (2005), the Petition included a settlement agreement, along with *pro forma* tariff sheets to implement certain terms of the settlement ("Settlement Agreement").

3. On ______________, 2006, the Commission issued notice of Eastern Shore's filing establishing a comment date of July 5, 2006. No protest or comment adverse to the Settlement Agreement was filed in the proceeding.

4. The Commission will grant Eastern Shore's Petition and approve the Settlement Agreement as fair and reasonable and in the public interest. The Settlement Agreement represents a compromise among all parties and avoids potential litigation.

Summary of the Proposed Settlement

5. Article I provides that the Settlement Agreement resolves all issues relating to sharing of certain project development costs relating to the Project described in Eastern Shore's Petition.

6. Article II states that within seven (7) business days of the "Effective Date" (defined in Article III) of the Stipulation and Agreement ("S&A"), Eastern Shore shall file tariff sheets that

are substantively identical to the *pro forma* tariff sheets included in the Settlement Agreement, to be effective on the Effective Date provided in Article III of the S&A.

7. Article III provides that the "Effective Date" of the S&A is the date upon which the Commission has approved the S&A by an order (a) that does not subject the S&A to modification or condition and (b) that is no longer subject to rehearing or appeal. Upon written notice to the Commission, Eastern Shore may waive conditions (a) or (b) above, or both, in which case the Effective Date shall be the date specified in Eastern Shore's written notice to the Commission. Within ten (10) days of the issuance of a Commission order approving this S&A, Eastern Shore shall inform all other persons by written notice of any Commission-imposed condition or modification that Eastern Shore will not waive pursuant to Article III.

8. Article IV sets forth certain reservations and miscellaneous provisions.

Conclusion

9. The Commission approves Eastern Shore's Petition for Approval of Settlement Agreement.

10. The Commission has reviewed the Settlement Agreement and finds that it is in the public interest, represents a fair and reasonable resolution of all issues. Accordingly, the Commission approves the Settlement Agreement. The Commission further notes that the settlement of the resolved issues will result in a significant savings in time and expense for all involved.

11. Pursuant to section 4(d) of the Natural Gas Act and Section 154.203 of the Commission's Regulations, 18 C.F.R. § 154.203, Eastern Shore is ordered to file, within seven (7) business days of the issuance of this order, actual tariff sheets implementing the Settlement Agreement, as reflected on the *pro forma* tariff sheets filed as part of the Settlement Agreement.

By direction of the Commission,

Magalie R Salas
Secretary

cc: All Parties

APPENDIX B

Eastern Shore Natural Gas Company
Firm Customers Supporting or Not Opposing the Settlement Agreement

The following list comprises 100 per cent of Eastern Shore's firm transportation customers:

Chesapeake Utilities Corporation

Delmarva Power & Light Company

Valero Energy Corporation

Peco Energy Company

Elkton Gas Company

Dow-Reichhold Chemicals

Formosa Plastics Corporation

City of Dover

Easton Utilities Commission

Playtex Products, Inc.

Eastern Shore Natural Gas Company
Docket No. RP06-___-000

APPENDIX C

Pro Forma Tariff Sheets

Eastern Shore Natural Gas Company
Docket No. RP06-___-000

Original Sheet No. ____

Section ___[GTC] Project Pre-Certification Cost Surcharge

1. Applicability: Shippers on Eastern Shore's system who enter into a Precedent Agreement with Eastern Shore to subscribe to firm transportation service capacity on the Project, described in the Stipulation and Agreement of Settlement approved by the Commission in Docket No. RP06-___-000 ("Participating Shippers"), shall be subject to a Pre-Certification Cost Surcharge, based on the formula set forth below. Eastern Shore will not seek to recover such costs from any other shipper on its system in this or any future Commission proceeding.

2. Formula for Determining Surcharge: The Pre-Certification Costs Surcharge to be charged to each Participating Shipper shall be determined as follows:

(a) In the event that the Project is not certificated by the Commission, Eastern Shore does not accept the certificate, or the Project is not completely constructed and placed in service, Eastern Shore shall compute all costs incurred through the date of the Final Order by the Commission, which is no longer subject to rehearing or appeal, authorizing or denying Eastern Shore's application to construct and operate the Project (the "Pre-Certification Costs Period"), including costs incurred by Eastern Shore for engineering, communications, governmental relations, economic studies, environmental, regulatory, and legal services (collectively, "Pre-Certification Costs"). Such Project Pre-Certification Costs shall be accounted for in accordance with the FERC's Uniform System of Accounts, and Eastern

Shore shall certify to each Participating Shipper the total amount of such Pre-Certifcation Costs.

(b) Each Participating Shipper's proportionate share of such Pre-Certification Costs shall be computed by taking its Maximum Daily Transportation Quantity ("MDTQ"), contained in its Project Precedent Agreement, divided by the sum of the MDTQs contained in all executed Project Precedent Agreements and multiplying such result by the total level of actual Pre-Certification Costs, such costs not to exceed three million dollars ($3 million). For Pre-Certification Costs in excess of $3 million dollars, each Participating Shipper's proportionate share shall be one (1) divided by the sum of all Participating Shippers plus Eastern Shore (For example, once total Pre-Certification Costs exceed $3 million, with a total of two (2) Participating Shippers each Participating Shipper's proportionate share of the Pre-Certification Costs over $3 million would equal: one (1) divided by three (3), or thirty-three and one-third (33 1/3) percent of such costs in excess of $3 million dollars.). Unless a change is agreed to in writing by a Participating Shipper, its total share of Pre-Certification Costs, excluding interest, shall in no event exceed two million dollars ($2 million).

3. Billing and Payment

Each Participating Shipper's proportionate share of Pre-Certification Costs shall: (i) be amortized and billed monthly over a period of twenty (20) years; and (ii) shall earn a return of 10.70% after tax (Eastern Shore's weighted cost of capital as determined in its most recent Section 4 general rate proceeding, RP02-34-000), such amount accruing, until date of payment by Participating Shipper.

Submission Contents

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

116 FERC ¶61,111

August 1, 2006

In Reply Refer To:
Eastern Shore Natural Gas Company
Docket No. RP06-404-000

Eastern Shore Natural Gas Company
417 Bank Lane
Dover, DE 19904

Attention: Elaine B. Bittner
Vice President

Reference: Petition for Approval of Settlement Agreement

Dear Ms. Bittner:

1. On June 28, 2006, Eastern Shore Natural Gas Company (Eastern Shore) submitted a Petition for Approval of a Settlement Agreement which would enable Eastern Shore to collect certain pre-certification costs from the parties agreeing to the Settlement in the event that a construction project to connect Eastern Shore with Dominion Cove Point LNG, LP is unsuccessful. As discussed below, the Commission will approve the Settlement as just and reasonable.

2. Eastern Shore states that it has operated interstate natural gas transmission facilities on the Delmarva Peninsula since 1959 and that it provides firm and interruptible transportation service to several local distribution companies (LDCs), as well as industrial and power generation customers. Eastern Shore states that it also provides firm storage service to several of its LDC customers. Eastern Shore states that currently, all of the gas it transports is received from Transcontinental Gas Pipe Line Corporation (Transco) and Columbia Gas Transmission Corporation (Columbia) at points of interconnection in Southeastern Pennsylvania and Northern Delaware, and that these points are upstream of Eastern Shore's customers on the Peninsula.

3. To meet future needs, Eastern Shore asserts that it must supplement its existing supply resources. Eastern Shore states that it is considering constructing pipeline facilities that would connect with the liquefied natural gas (LNG) facilities of Dominion Resources at Cove Point, Maryland, that would then cross under the Chesapeake Bay and

interconnect with Eastern Shore's existing pipeline facilities approximately at the midpoint of the Delmarva Peninsula. According to Eastern Shore, such a project would provide the necessary infrastructure to make a new source of supply available to Eastern Shore's customers and reduce their dependence on Transco and Columbia as the sole current sources of supply and upstream capacity for transportation to Eastern Shore's system. Eastern Shore asserts that by constructing new pipeline infrastructure to connect with its existing main pipelines about midway down the Delmarva Peninsula, Eastern Shore would: (1) enhance operational flexibility on its system; (2) strengthen and expand its ability to meets its customers' demands on both the northern and southern halves of its system; and (3) provide the opportunity for low cost future expansion on its system.

4. Eastern Shore explains that the costs of licensing, permitting, and constructing such a project will be far greater than any of its prior expansion projects. To justify such a large investment, Eastern Shore states that it needs long-term, firm commitments from customers sufficient to make the project economical. Over the past few years, Eastern Shore asserts that it has surveyed its customers' interest in such an expansion in open seasons to measure its customers' needs for such additional capacity. Eastern Shore states that two of its longstanding LDC customers, Chesapeake Utilities Corporation and Delmarva Power & Light Company, have signed binding precedent agreements specifying negotiated rates with twenty year terms, subscribing to a total of 60,000 Dth/day of firm capacity on the proposed project.

5. Eastern Shore states that the proposed Settlement will resolve certain issues on its system. The terms of the Settlement entitle Eastern Shore to collect certain pre-certification costs (*i.e.*, engineering, communication, governmental relations, economic studies and environmental, regulatory and legal service costs), through a surcharge to those shippers who enter into a precedent agreement with Eastern Shore to subscribe to firm transportation service capacity on the project. The surcharge would apply only to those shippers that sign the precedent agreements and would only apply in the event that: (1) the project is not certificated by the Commission; (2) Eastern Shore does not accept the certificate or; (3) the project is not completely constructed and placed in service. No non-participating shipper would be at risk for the pre-certification costs because pursuant to the terms of the Settlement Eastern Shore will not seek to recover such costs from any shipper on its system in any other Commission proceeding instituted following approval of the Settlement.

6. Under the proposed Settlement, each participant would be allocated a proportionate share of the total pre-certification costs based on each shipper's Maximum Daily Transportation Quantity (MDTQ) to the total MDTQ contained in all executed project precedent agreements up to $3 million of total pre-certification costs. For pre-certification costs in excess of $3 million, each participating shipper plus Eastern Shore will be allocated an equal portion of the pre-certification costs. The pre-certification costs, exclusive of interest, for each shipper would be capped at $2 million.

7. Each participating shipper's proportionate share of pre-certification costs would be amortized and billed over a period of 20 years and will earn a return of 10.70 percent after tax (Eastern Shore's weighted cost of capital as determined in its most recent Section 4 general rate proceeding) until date of payment by Participating Shipper. The Settlement also provides that Eastern Shore will file tariff sheets with the Commission within seven (7) days of the effective date of the Settlement.

8. Public notice of Eastern Shore's filing was issued on July 7, 2006, with interventions and protests due as provided in section 154.210 of the Commission's regulations (18 C.F.R. §154.210 (2005). Pursuant to Rule 214 (18 C.F.R. § 385.214 (2005)), all timely motions to intervene and any motions to intervene out-of-time filed before the issuance date of this order are granted. Granting late intervention at this stage of the proceeding will not disrupt the proceeding or place additional burden on existing parties. Chesapeake Utilities Corporation (Chesapeake), Worcester County Economic Development (WCED), Salisbury-Wicomico Economic Development, Inc. (SWED) and Delmarva each filed statements supporting the Settlement.

9. Natural Gas Resources LLC (NGR) filed a protest to the Settlement and Eastern Shore filed an answer to the protest. The Commission's rules of practice and procedure generally prohibit answers to protests or answers.[1] Accordingly, the Commission will not accept Eastern Shore's answer in this proceeding as it is not necessary to understand or clarify the issues in this case. In its protest, NGR states that it is a sponsor of a natural gas system on the Delmarva Peninsula that would serve new and existing natural gas loads in the southern part of the Peninsula. NGR further states that it began development of its project in 1999, with substantial market evaluation and engineering design work performed in subsequent years. NGR explains that, as a new entrant to this market, it does not have existing customers to which it could bill its development costs if its project is unsuccessful and, as such, believes that giving Eastern Shore the right to bill its customers for unsuccessful development costs puts NGR at a disadvantage.

10. Chesapeake and Delmarva, as signatories to the Settlement, state that they fully support approval of the Settlement because they believe the project will provide numerous benefits to their natural gas distribution customers by, among other things, (1) reducing their dependence on Transco and Columbia as its sole sources of upstream pipeline capacity and (2) providing access to competitively priced LNG supply from the Cove Point LNG facility. In its statement of support, SWED requests the Commission to approve the Settlement because it believes that the kind of risk-sharing proposed by Eastern Shore and agreed to by its largest customers will benefit the people and businesses in the region. WCED maintains that the project is necessary because it will develop Eastern Shore's natural gas infrastructure in order to supply natural gas on a reliable basis and is important to economic development and vitality.

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[1] 18 C.F.R. § 385.213(a)(2) (2005).

11. The Settlement Agreement sponsored by Eastern Shore is supported or not opposed by any of Eastern Shore's firm service customers. The instant Settlement allows Eastern Shore to explore the viability of constructing new pipeline infrastructure on its system which would provide Eastern Shore's customers access to a new source of supply and would add greater flexibility to its system. Further, the cost risks imposed by the Settlement are limited only to those participants who are signatories to the Agreement. We find that the instant Settlement promotes the exploration of infrastructure development by the pipeline and its customers.

12. The Commission rejects NGR's protest to the instant Settlement. NGR is not a customer of Eastern Shore but is only a potential competitor. As such, NGR argues that the Commission's approval of the instant Settlement will promote an uneven playing field between it and Eastern Shore as it seeks to develop its own plans for pipeline infrastructure on the Delmarva Peninsula. However, the Commission finds that approval of agreements of the type reflected in the instant Settlement will encourage pipelines to explore the construction of needed pipeline infrastructure with their customers. While at this point NGR does not appear to have customers involved in its consideration of a pipeline development project, the Commission finds that this should not retard the efforts of Eastern Shore to develop its own projects. The Commission would grant equal consideration to any such arrangement NGR might reach with future customers interested in its project.

13. Accordingly, the Commission approves the Settlement and finds that it is just and reasonable. Approval of this Settlement does not constitute a precedent regarding any principle or issue in this proceeding.

By direction of the Commission. Commissioner Wellinghoff voted present.

Magalie R. Salas,
Secretary.

EASTERN SHORE NATURAL GAS COMPANY
GENERAL TERMS AND CONDITIONS
(Continued)

41. Pre-Certification Cost Surcharge

(a) Applicability

Shippers on Eastern Shore's system who enter in a Precedent Agreement with Eastern Shore to subscribe to firm transportation service capacity on the Project, described in the Stipulation and Agreement of Settlement approved by the Commission in Docket No. RP06-404-000 ("Participating Shippers"), shall be subject to a Pre-Certification Cost Surcharge, based on the formula set forth below. Eastern Shore will not seek to recover such costs from any other Shipper on it system in this or any future Commission proceeding.

(b) Formula for Determining Surcharge

The Pre-Certification Costs Surcharge to be charged to each Participating Shipper shall be determined as follows:

(1) In the event that the Project is not certificated by the Commission, Eastern Shore does not accept the certificate, or the Project is not completely constructed and placed into service, Eastern Shore shall compute all costs incurred through the date of the Final Order by the Commission, which is no longer subject to rehearing or appeal, authorizing or denying Eastern Shore's application to construct and operate the Project (the "Pre-Certification Costs Period"), including costs incurred by Eastern Shore for engineering, communications, governmental relations, and legal services (collectively, "Pre-Certification Costs"). Such Project Pre-Certification Costs shall be accounted for in accordance with the FERC's Uniform System of Accounts, and Eastern Shore shall certify to each Participating Shipper the total amount of such Pre-Certification Costs.

Previous Next

EASTERN SHORE NATURAL GAS COMPANY
GENERAL TERMS AND CONDITIONS
(Continued)

41. Pre-Certification Cost Surcharge (Continued)

(b) Formula for Determining Surcharge (Continued)

(2) Each Participating Shipper's proportionate share of such Pre-Certification Costs shall be computed by taking its Maximum Daily Transportation Quantity ("MDTQ"), contained in its Project Precedent Agreement, divided by the sum of the MDTQ's contained in all executed Project Precedent Agreements and multiplying such result by the total level of actual Pre-Certification Costs, such costs not to exceed three million dollars ($3 million). For Pre-Certification Costs in excess of $3 million, each Participating Shipper plus Eastern Shore (for example, once total Pre-Certification Costs exceed $3 million, with a total of two (2) Participating Shippers each Participating Shipper's proportionate share of the Pre-Certification Costs over $3 million would equal: one (1) divided by three (3), or thirty-three and one-third (33 1/3) percent of such costs in excess of $3 million dollars). Unless a change is agreed to in writing by a Participating Shipper, its total share of Pre-Certification Costs, excluding interest, shall in no event exceed two million dollars ($2 million).

(c) Billing and Payment

Each Participating Shipper's proportionate share of Pre-Certification Costs shall: (1) be amortized and billed monthly over a period of twenty (20) years; and (2) shall earn a return of 10.70% after tax, such amount accruing, until date of payment by Participating Shipper.

TESTIMONY OF MICHAEL CASSEL

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
CHESAPEAKE UTILITIES CORPORATION	)	
FOR APPROVAL OF A CHANGE IN ITS	)	P.S.C. DOCKET NO. 09-
GAS SALES SERVICE RATES ("GSR")	)	
TO BE EFFECTIVE NOVEMBER 1, 2009	)	

DIRECT TESTIMONY OF MICHAEL D. CASSEL

On Behalf of Chesapeake Utilities Corporation

Delaware Division

Submitted for filing: September 4, 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Michael D. Cassel and I am a Regulatory Analyst III with Chesapeake Utilities Corporation ("Chesapeake" or the "Company"). My business address is 350 S. Queen Street, Dover, Delaware 19904.

Q. DESCRIBE BRIEFLY YOUR EDUCATION AND RELEVANT PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science Degree in Accounting from Delaware State University in Dover, Delaware in 1996. I was hired by Chesapeake as a Regulatory Analyst III in March 2008. As a Regulatory Analyst III, I have primarily been involved in the areas of gas cost recovery, rate of return analysis, and budgeting for the Delaware natural gas distribution company. Prior to joining Chesapeake, I was employed by J.P. Morgan Chase & Company, Inc. from 2006 to 2008 as a Financial Manager in their card finance group. My primary responsibility in this position was the development of client specific financial models and profit loss statements. I was also employed by Computer Sciences Corporation as a Senior Finance Manager from 1999 to 2006. In this position, I was responsible for the financial operation of the company's chemical, oil and natural resources business. This included forecasting, financial close and reporting responsibility, as well as representing Computer Sciences Corporation's financial interests in contract/service negotiations with existing and potential clients. From 1996 to 1999 I was employed by J.P. Morgan, Inc. where I had various accounting/finance responsibilities for the firms private banking clientele.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. Yes. I have testified before the Commission during the Company's previous Gas Sales Service Rate ("GSR") proceeding.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss the mechanics of the three Gas Sales Service Rates ("GSR"), explain the forecasted demand and commodity costs, address the development of the forecasted firm and interruptible sales volumes and total system requirements, discuss the development of the unaccounted for gas volumes, as well as the mechanics of the Delaware Division's proposed balancing rates for transportation service under the Large Volume Service ("LVS"), High Load Factor Service ("HLFS"), and Interruptible Service ("ITS") rate schedules. Finally, I will illustrate the impact of the proposed GSR charges on an average residential customer's bill.

Q. ARE THERE ANY SCHEDULES INCLUDED WITH YOUR DIRECT TESTIMONY?

A. No. In my testimony, I will be referencing the Schedules attached to the testimony of Jennifer A. Clausius.

Q. WHAT GAS SALES SERVICE RATE LEVELS ARE YOU PROPOSING IN THIS PROCEEDING TO BE EFFECTIVE WITH SERVICE RENDERED ON AND AFTER NOVEMBER 1, 2009?

A. The Company proposes the following Gas Sales Service Rates to be effective for service rendered on and after November 1, 2009: $0.956 per Ccf for customers served under Rate Schedules RS-1, RS-2, GS, MVS, and LVS, $0.645 per Ccf for customers served under Rate Schedules GLR and GLO, and $0.797 per Ccf for customers served under Rate Schedule HLFS.

Q. WHAT EFFECT WILL THIS PROPOSED DECREASE IN THE GSR HAVE UPON THE AVERAGE RESIDENTIAL HEATING CUSTOMER?

A. As compared to the rates that were in effect February 1, 2009 an average RS-2 customer using 700 Ccf per year will experience an annual decrease of approximately 16% or $17 per month. During the winter heating season, a typical RS-2 customer on Chesapeake's system using 110 Ccf per month will experience a decrease of approximately 18% or $32 per winter month. A RS-2 customer using 120 Ccf per month will experience a decrease of approximately 18% or $34 per winter month. Additionally, comparing the rates that were in effect November 1, 2008, an average RS-2 customer using 700 Ccf per year will experience an annual decrease of approximately 25% or $30 per month. During the winter heating season, a typical customer on Chesapeake's system using 110 Ccf per month will experience a decrease of approximately 28% or $56 per winter month. An RS-2 customer using 120 Ccf per month will experience a decrease of approximately 28% or $61 per winter month.

Q. PLEASE DESCRIBE HOW YOU CALCULATED THE PROPOSED GAS SALES SERVICE RATE LEVELS TO BE IMPLEMENTED IN THIS PROCEEDING.

A. The rates were calculated based on the estimated purchased gas costs and estimated sales volumes for the twelve months ending October 31, 2010 and are summarized on Schedule A.1. As shown on Schedule A.1, total projected firm gas costs recoverable through the gas cost recovery mechanism are $41,810,055. This total is comprised of $15,820,014 of fixed costs and $25,990,040 of variable costs. The three gas cost rates shown at the top of Schedule A.1, which include a fixed rate (used to calculate separate demand rates), a variable / commodity rate, and a total rate or system average rate, are the key components for calculating separate Gas Sales Service Rates for different services.

Q. CAN YOU BRIEFLY SUMMARIZE THE REASONS WHY THE THREE GSR CHARGES ARE DECREASING FROM THE COMPANY'S PREVIOUS FILING?

A. The analysis of the change in gas costs and Gas Sales Service Rates from the Company's last gas cost recovery filing is summarized on Schedule E. As shown on this schedule, variable or commodity gas costs are anticipated to decrease by $13,328,271 since the last GSR filing. The variable costs contained in this filing are decreasing primarily due to the projected cost of flowing commodity gas for the upcoming year decreasing from the flowing commodity gas costs included in the previous GSR filing with rates effective on and after February 1, 2009.

As shown on this schedule, fixed costs are anticipated to increase by $1,943,717 since February 1, 2009, the date of the last change in the Company's GSR. The increase in fixed gas costs is mainly attributable to a combination of increased daily firm transportation entitlements on the Transcontinental Gas Pipe Line Company, LLC ("Transco"), Eastern Shore Natural Gas Company ("ESNG") pipeline, and Columbia Gas Transmission Company ("Columbia"). These increased entitlements are discussed further in the direct testimony of Marie E. Kozel.

Q. PLEASE DESCRIBE THE PROCESS THE COMPANY USED TO DETERMINE ITS GSR LEVELS AND THE VARIOUS COMPONENTS OF

THE DELAWARE DIVISION'S GSR CALCULATIONS AS SHOWN ON SCHEDULE A.1.

A. Schedule A.1 is a summary of the calculation of the three proposed GSR levels. The calculations of the proposed GSR levels have been made in accordance with the provisions set forth in the Delaware Division's GSR tariff clause. The process to determine the GSR charges consists of three major steps:

1. Develop the sales and associated gas supply requirements forecast.
2. Forecast supplier rates and calculate annual purchased gas costs associated with serving the Company's firm customers.
3. Derive the GSR charges utilizing the results of the first two steps and the process below:

Step 3 is summarized on Schedule A.1. Initially, three gas cost rates must be established to calculate the three separate GSR charges: a fixed rate, a commodity rate and a system average rate. Based on total firm gas costs recoverable through the gas cost recovery mechanism for the GSR levels to be effective November 1, 2009, the three gas cost rates are calculated as follows:

Fixed Rate - \$25.46 / Ccf	(Total fixed costs of \$15,820,014 divided by the firm peak day capacity requirements of 621,266 Ccf)

Commodity Rate - $0.575 / Ccf	(Total firm commodity costs of $25,990,040 divided by firm sales volumes of 45,209,210 Ccf for the period November 2009 through October 2010)
System Average Rate - $0.925 / Ccf	(Divide total firm gas costs of $41,810,055 by the firm sales volume of 45,209,210 Ccf)

From these three rates, different methodologies are applied in order to calculate the Gas Sales Service Rates that more closely align the Gas Sales Service Rates with actual gas costs identified for providing services associated with different rate schedules or customer classes.

Q. PLEASE EXPLAIN THE THREE METHODOLOGIES UTILIZED TO CALCULATE THREE SEPARATE GAS SALES SERVICE RATES USING THE FIXED RATE, COMMODITY RATE AND SYSTEM AVERAGE RATE AS PREVIOUSLY DESCRIBED.

A. Schedule A.1 also provides a summary of the development of the three separate Gas Sales Service Rates by applying the tariff language described in the Delaware Division's tariff on Sheet No. 42.2.

Rate Schedule HLFS

This GSR charge, applicable to any customer qualifying for High Load Factor Service (HLFS), is calculated based on the combination of a weighted average demand and commodity rate developed on an overall seventy-four percent (74%) load factor for the customer class and the overall system weighted average cost rate. The 74% load factor is included on Schedule J. This means that the fixed gas cost rate of $25.46 per Ccf, as previously described, is divided by 270 days (74% of 365 days in a year) to calculate a demand rate of $0.094 per Ccf. This rate is then added to the commodity rate, as previously described, of $0.575 per Ccf to calculate a volumetric rate of $0.669 per Ccf. The arithmetic average of this volumetric rate ($0.669 per Ccf) and the system average rate ($0.925 per Ccf) is $0.797 per Ccf, which equals the GSR charge for HLFS customers. Total costs associated with HLFS ($9,139,709) are projected by multiplying the GSR charge ($0.797 per Ccf) by the projected sales volumes for HLFS (11,467,640 Ccf).

Rate Schedules GLO and GLR

All customers served under these Gas Lighting rate schedules will be subject to the same GSR charge. This rate is calculated using weighted average demand and commodity rates through a single gas cost rate per Ccf, based on a 100% load factor. The demand rate of $0.070 per Ccf ($25.46 / 365) plus the commodity rate of $0.575 per Ccf, produces a GSR charge of $0.645 per Ccf. Total costs associated with Gas Lighting Services of $942 are a result of multiplying the $0.645 per Ccf GSR charge by the annual sales volumes for these services of 1,460 Ccf.

Rate Schedules RS-1, RS-2, GS, MVS and LVS

These rate schedules are assigned the remaining firm purchased gas costs after the firm purchased gas costs have been calculated for the above mentioned rate schedules ($41,810,055 - $9,139,709 - $942 = $32,669,404). Associated costs are divided by the remaining volume (45,209,210 – 11,467,640 – 1,460 = 33,740,110) to develop a rate of $0.968 per Ccf, less the portion of any shared margins ($0.012 per Ccf) as shown on Schedule A.2. All customers served under rate schedules RS-1, RS-2, GS, MVS and LVS will be charged $0.956 per Ccf for service rendered on and after November 1, 2009.

Q. AS INDICATED IN YOUR TESTIMONY, THE FIRST STEP IN CALCULATING THE PROPOSED GSR CHARGES IS THE DEVELOPMENT OF THE SALES AND ASSOCIATED GAS SUPPLY REQUIREMENTS FORECAST. HOW ARE THE SALES AND SUPPLY REQUIREMENTS FORECASTS DEVELOPED IN THIS PROCEEDING?

A. A forecast of purchased gas costs must start with a forecast of demand or sales volumes for the Company's distribution system. Based on meeting the sales forecast, the Company develops a forecast of the associated purchases or supply requirements. For the purpose of this proceeding, the sales forecast began with an analysis of the major variables that affect sales volumes. These variables include such items as the number of customers to be served, the rate schedule classification of those customers (i.e. large volume, high load factor, etc.), temperature, and the larger individual commercial and industrial customer sales volumes or demands. Sales volumes are normalized based on a ten-year average of degree days for the months of July 1999 through June 2009.

Q. HAS A SCHEDULE BEEN INCLUDED SETTING FORTH THE ESTIMATED VOLUMES OF GAS TO BE BILLED TO CUSTOMERS DURING THIS PERIOD?

A. Yes. Schedule C.1 shows Chesapeake's projected sales volumes by customer class for the determination period of the twelve months ending October 31, 2010.

Q. PLEASE DISCUSS FURTHER THE DEVELOPMENT OF THE SALES FORECAST SHOWN ON SCHEDULE C.1

A. Forecasted sales were used for the entire twelve-month period of November 2009 through October 2010. Forecasted sales were developed based upon the actual sales volumes billed to each customer class during each month for the prior year with adjustments to reflect average temperature, customer growth and customers switching among rate classes.

Q. HOW ARE THESE CUSTOMER ADJUSTMENTS REFLECTED IN THE TWO RESIDENTIAL SERVICE CLASSES?

A. For RS-2 customers, the Company has projected an increase of approximately 1,049 customers over the twelve-month period ending October 31, 2009, with the majority of the increase representing growth in new customers. The Company did not project a significant change to the number of RS-1 customers.

Q. HOW ARE THESE CUSTOMER ADJUSTMENTS REFLECTED IN THE FIRM COMMERCIAL AND INDUSTRIAL CLASSES?

A. With respect to the Commercial and Industrial customers, the Company projects an overall increase of approximately 118 customers over the previous twelve-month period.

Q. PLEASE DISCUSS ANY OTHER FIRM CUSTOMER ADJUSTMENTS.

A. With respect to the number of Gas Lighting customers, no significant changes are projected during this twelve-month period.

Q. DOES THE COMPANY HAVE ANY PROJECTIONS FOR THE NUMBER OF FIRM COMMERCIAL AND INDUSTRIAL CUSTOMERS THAT MAY CHOOSE TO TRANSPORT ON ITS DISTRIBUTION SYSTEM AND THE VOLUMES ASSOCIATED WITH THESE CUSTOMERS FOR THIS PERIOD?

A. Yes. The Company has not included in its projections any new firm commercial or industrial customers switching from sales service to transportation service during the determination period. This filing includes projections for gas to be transported on the Company's distribution system for those customers who are currently receiving transportation service based on the Company's current eligibility requirements. There are sixty-five (64) firm commercial / industrial customers and four (4) interruptible commercial / industrial customers who will be transporting their own gas on the Delaware Division's distribution system. The Company has estimated the firm commercial / industrial transportation volumes to be approximately 1,273,418 and the interruptible commercial / industrial transportation volumes to be approximately 388,661 Mcf during this period.

Q. PLEASE EXPLAIN HOW THE PROJECTED SALES VOLUMES WERE USED TO CALCULATE THE ASSOCIATED GAS SUPPLY REQUIREMENTS REQUIRED BY THE DELAWARE DIVISION DURING THE DETERMINATION PERIOD.

A. Using the projected sales volumes from Schedule C.1 as a starting point, adjustments due to cycle billing, unaccounted for gas and company use gas were derived in order to calculate the total gas supply requirements for the period.

Q. PLEASE EXPLAIN THE CYCLE BILLING ADJUSTMENT AS SHOWN ON SCHEDULE C.1.

A. All sales volume projections included in this GSR filing are associated with a respective billing month while the Delaware Division's purchases are recorded on a calendar month basis. Chesapeake includes a cycle billing adjustment in its calculation of the GSR charges for the purpose of accounting for the difference between a billing month and a calendar month. The cycle billing adjustment is calculated by first dividing the projected, normalized firm sales volumes for each month into a base load and a heating load. The heating load is then multiplied by the difference between the normal calendar month degree days and the normal billing month degree days to calculate the cycle billing adjustment.

Q. WHAT IS THE LEVEL OF COMPANY USE GAS PROJECTED DURING THE DETERMINATION PERIOD?

A. Company Use Gas is projected to be 2,096 Mcf for this determination period. This projection is approximately the same level of volume experienced by the Company during the actual twelve months ended July 31, 2009.

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE PROJECTED UNACCOUNTED FOR GAS AS SET FORTH IN SCHEDULE C.1.

A. An unaccounted for gas volume of 86,915 Mcf has been projected for the twelve months ending October 31, 2010. Unaccounted for gas is calculated by multiplying the respective sales volumes for each month by

3.46% and subtracting the estimated Company Use and Pressure Compensation for the month. The 3.46% utilized in this GSR calculation includes volumes attributed to metering pressure differential and is based on the most recent actual five-year history of unaccounted for gas volumes. The use of a five year history of unaccounted for gas volumes was approved by the Public Service Commission by Order No. 4189 in PSC Docket No. 95-206.

Q. DID THE SCHEDULES SUPPORTING THE CALCULATION OF PROJECTED UNACCOUNTED FOR GAS CHANGE SINCE THE LAST GSR FILING?

A. Yes they did. As mentioned in the testimony of Jennifer A. Clausius the Company completed an analysis of whether it would be cost effective to replace some or all of the Company's meters that are not pressure compensated. This analysis was filed with the Delaware Public Service Commission on April 7, 2009. As a result of this analysis, the Company identified some formatting changes that were needed on Schedules C.1 and G. In the proposal submitted on April 7, 2009 the Company informed the Commission that, effective with its next GSR filing, it would be making changes on these two Schedules.

Q. WHAT CHANGES DID THE COMPANY MAKE TO SCHEDULE C.1?

A. Schedule C.1 has historically reflected a line labeled "Unaccounted For Gas". This line has included both the amount for unaccounted for gas and the amount for pressure compensation. As a result of the analysis completed, the Company added an additional line labeled "Pressure Compensation" and separated it from the unaccounted for gas balance. This allows the amount for unaccounted for gas and pressure compensation to be reflected as separate line items on Schedule C.1. The underlying calculations to these two lines have not changed.

Q. PLEASE DISCUSS THE CHANGE MADE TO SCHEDULE G.

A. The Company made the following three (3) changes to Schedule G.

1) The title of the Schedule was changed from "Unaccounted For Gas Volumes" to "Unaccounted For, Company Use & Pressure Compensation Gas Volumes". This title change more accurately reflects the detail provided on this Schedule.

2) The heading on column three (3) was changed from "Unaccounted For and Company Use" to "Unaccounted For, Pressure Compensation and Company Use". As before, the Company believes this more accurately represents the detail being provided for on this schedule.

3) A footnote was added for column five (5) that identifies the calculation represented as that required to pressurize gas delivered from the ESNG transmission pipeline to a standard pressure to be

used on the Company's distribution system. The underlying calculation of pressure compensation has not changed.

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE PROJECTED COST OF FIRM SALES FOR THE TWELVE-MONTH PERIOD ENDING OCTOBER 31, 2010.

A. The projected cost of firm sales is detailed on a monthly basis throughout the seven pages of Schedule C.2. In calculating the proposed cost of gas for the period November 1, 2009 through October 31, 2010, the total projected supply requirements were allocated between the different categories of gas (commodity and storage) available to meet the projected demand. Pages 1 and 2 of Schedule C.2 primarily calculate the fixed costs of firm transportation on Columbia, Columbia Gulf Transmission ("Columbia Gulf"), Transco, and ESNG. A summary of storage demand and capacity charges is also included on these two pages. Pages 3, 4 and 5 calculate the gas commodity costs associated with firm transportation service. As summarized on Page 4 of Schedule C.2, the projected cost of storage gas commodity for withdrawals during this period has been calculated using the actual purchases and costs for the months of April 2009 through July 2009 and projected purchases and costs for August 2009 through October 2009. The twelve-month period ending March 2010 is used for the calculation of the storage gas demand cost to properly reflect the amounts to be expensed during the determination year. The rates used in the commodity gas purchase projections for flowing commodity gas for November 2009 through October 2010 are based on natural gas commodity futures market prices during the third week August 2009.

Q. HAS THE COMPANY INCLUDED ANY SUPPLIER REFUNDS IN THIS ANNUAL GAS SALES SERVICE RATE FILING?

A. Yes. The Company has included one supplier refund in the GSR calculation for this determination period. The refund, in the amount of $82,931, represents the Delaware Division's estimated portion of ESNG's interruptible margin sharing mechanism provision approved by the Federal Energy Regulatory Commission. The projected supplier refund is included in the Company's total firm gas cost calculation on Schedule B.

Q. PLEASE EXPLAIN THE CHANGE IN THE PROJECTED FIRM COST OF GAS FOR THE TWELVE MONTHS ENDING OCTOBER 31, 2010 AS SHOWN ON SCHEDULE B COMPARED TO NINE MONTHS OF ACTUAL COSTS AND THREE MONTHS OF PROJECTED COSTS FOR THE TWELVE-MONTH PERIOD ENDING OCTOBER 31, 2009.

A. Schedule F compares the projected firm cost of gas for the twelve months ending October 31, 2010 utilized in this proceeding to the nine months of actual gas costs and three months of projected gas costs for the twelve-month period ending October 31, 2009. In addition, for informational purposes, the actual firm cost of gas for the three prior determination periods ended October 2008, 2007, 2006 are shown. Chesapeake anticipates a decrease in firm gas cost per Mcf from $12.4718 per Mcf to $10.5279 per Mcf or a $1.9439 per Mcf decrease for the twelve months ending October 31, 2010. As indicated on Schedule F, the $1.9439 per Mcf decrease is mainly attributable to a projected decrease in variable gas costs per Mcf based on decreased flowing gas commodity projections for the determination period.

Q. PLEASE EXPLAIN SCHEDULES D.1 AND D.2 IN THIS GSR FILING.

A. Schedule D.1 sets forth the calculation of the purchased gas over/under collection by month for the twelve-month period ending October 31, 2009. The projected over collection balance at October 31, 2009 that is carried forward into this annual filing is $4,109,549.

Schedule D.2 reflects the shared margins over/under refund for the twelve-month determination period ending October 31, 2009. Based on this twelve-month determination period, the Company's under refunded shared margins are $47,201. This amount is also included in the shared margin calculation on Schedule A.2.

Q. PURSUANT TO THE PROVISIONS OF THE TARIFF CONCERNING THE UNACCOUNTED FOR GAS INCENTIVE MECHANISM APPROVED BY ORDER NO. 3648, THE COMPANY AS PART OF ITS ANNUAL GSR

FILING IS REQUIRED TO PROVIDE THE COMMISSION STAFF WITH ACTUAL UNACCOUNTED FOR GAS VOLUMES FOR THE PRECEDING TWELVE MONTH PERIOD ENDED JULY 31. HAS THE COMPANY INCLUDED A SCHEDULE SHOWING THE REQUIRED INFORMATION?

A. Yes. Schedule G represents the actual unaccounted for gas volumes for the twelve months ended July 31, 2009.

Q. WHAT WERE THE UNACCOUNTED FOR GAS TARGET PERCENTAGE AND DEAD BAND PERCENTAGES APPROVED FOR THE UNACCOUNTED FOR GAS INCENTIVE MECHANISM IN PSC DOCKET NO. 92-87F?

A. The Unaccounted For Gas Target approved was 3.20% of total gas sendout or total gas requirements. The Dead Band approved was +/- 0.5% points around the 3.20% target level. Unaccounted For Gas Volumes that are within 2.70% to 3.70% of total gas sendout are considered to be within this band and meeting the objectives of this mechanism.

Q. WHAT WAS THE ACTUAL LEVEL OF UNACCOUNTED FOR GAS VOLUMES FOR THE TWELVE MONTHS ENDED JULY 31, 2009 COMPARED TO THE INCENTIVE MECHANISM TARGETS?

A. The actual unaccounted for gas percentage, as established by the approved guidelines in PSC Docket No. 92-87F, for the twelve months ended July 31, 2009, was 1.98% of total gas requirements. This percentage is under the targeted percentage of 3.20% and is also under the dead band range of 2.70% to 3.70%.

Q. WHAT IS THE COMPANYS PROJECTED CAPACITY RELEASE TO FIRM TRANSPORTATION CUSTOMERS ON ESNG'S SYSTEM IN THIS FILING?

A. The Company credits 100% of the capacity released for the Delaware Division's firm transportation customers to the firm sales customers due to the market on ESNG for this capacity. The Company has estimated this capacity release value to be $1,401,759 for the twelve-month period ending October 2010 as calculated on Schedule I and shown as a reduction to fixed demand costs on Schedule B. The total peak day firm entitlements on ESNG are projected to be 65,704 Dts per day for this determination period of which 6,194 Dts per day of Daily Contract Quantity entitlements are projected to be released to firm transportation customers, or approximately nine percent (9%) of the Delaware Division's peak day capacity on ESNG.

Q. EARLIER IN THIS TESTIMONY YOU MENTIONED THAT YOU WERE PROPOSING A CHANGE TO THE DELAWARE DIVISION'S FIRM BALANCING RATES FOR TRANSPORTATION CUSTOMERS BEING SERVED UNDER RATE SCHEDULES "LVS", "HLFS" AND THE

INTERRUPTIBLE BALANCING RATE FOR TRANSPORTATION CUSTOMERS BEING SERVED UNDER RATE SCHEDULE "ITS". PLEASE EXPLAIN WHY THE CHANGES TO THE GAS SALES SERVICE RATES AND THE BALANCING RATES ARE BEING PROPOSED IN THE SAME DOCKET.

A. Chesapeake's firm transportation balancing rates are calculated in accordance with the methodology approved in PSC Docket No. 95-73, Phase II, by Order No. 4400 and are based on Chesapeake's annual purchased gas costs. As a result of this order, Chesapeake is required to update its balancing rates for "LVS" and "HLFS" on an annual basis at the time of its annual Gas Sales Service Rate application. Chesapeake also agreed to update its balancing rate for "ITS" during its annual Gas Sales Service application as a result of Order No. 7434 issued on September 2, 2008 in PSC Docket No. 07-186.

The relationship between the GSR charges and the transportation balancing rates exist because the gas costs being presented in this GSR filing are the same gas costs that are used to calculate the transportation balancing rates.

Q. PLEASE STATE THE BALANCING RATES THAT ARE BEING PROPOSED IN THIS FILING.

A. Chesapeake is proposing a decrease in the firm balancing rate for transportation customers served under Rate Schedule "LVS" from $0.060

per Ccf to \$0.056 per Ccf to be effective for service rendered on and after November 1, 2009. The Company is proposing a decrease in the firm balancing rate for transportation customers served under Rate Schedule "HLFS" from \$0.019 per Ccf to \$0.007 per Ccf to be effective for service rendered on and after November 1, 2009. The Company is proposing a decrease in the interruptible balancing rate for transportation customers served under Rate Schedule "ITS" from \$0.004 per Ccf to \$0.002 per Ccf to be effective for service rendered on and after November 1, 2009.

Q. WHAT IS THE PRIMARY REASON FOR THE CHANGE IN THE BALANCING RATES THAT IS BEING PROPOSED?

A. The primary reason for the decrease in the firm balancing rate for transportation customers served under Rate Schedule "LVS" that is being proposed is because of an adjustment to the storages being used to balance. The primary reason for the decrease in the firm balancing rate for transportation customers served under Rate Schedule "HLFS" that is being proposed is because of an increase in the annual load factor for the class from 53.69% in the last filing to 74.16% as shown on Schedule J. The primary reason for decrease in the interruptible balancing rate for transportation customers served under Rate Schedule "ITS" that is being proposed is a result of an increase in the load factor from 47.10% in the last filing to 63.75% in this filing.

Q. WHAT GAS SUPPLY RESOURCES IS THE COMPANY USING IN DEVELOPING THE BALANCING SERVICE RATES BEING SUBMITTED IN THIS FILING?

A. Schedule J, Page 1 of 4 shows the Delaware Division's gas supply resources being used in developing the balancing service rates along with the purchased gas costs associated with these gas supply resources. All of these resources provide firm deliveries that vary in daily entitlements and duration. The Company also plans on using the propane peak shaving facilities as a gas supply resource in its balancing services. The Delaware Division currently has 12,048 Dt of propane peak shaving capacity available on a peak day to supplement its current pipeline entitlements.

Q. PLEASE BRIEFLY EXPLAIN HOW THE OVERALL COSTS OF THE GAS SUPPLY RESOURCES WERE DEVELOPED ON SCHEDULE J.

A. The Delaware Division's gas costs associated with the gas supply resources for balancing services are based on the same costs contained in the development of the GSR charges. The gas supply resources and their costs are separated into fixed gas supply resources and variable gas supply resources. The Delaware Division's storage demand and capacity, and propane peak shaving facilities are related to the fixed gas supply resources, while storage injection and withdrawal volumes are related to the variable gas supply resources.

Q. HOW WAS THE AVERAGE ANNUAL RATE OF APPROXIMATELY $120 PER DT FOR THE FIXED GAS SUPPLY RESOURCES DETERMINED ON SCHEDULE J, PAGE 1 OF 4?

A. The gas costs were determined for each of the fixed gas supply resources to be used by the Company in performing this balancing service. The total annualized gas supply costs of $3,745,068 were divided by the daily entitlement of 31,099 Dt to derive the annual amount of $120.4241 per Dt for these fixed gas supply resources in the balancing service.

Q. HOW WAS THE COST OF THE VARIABLE GAS SUPPLY RESOURCES DETERMINED IN THIS PROCEEDING?

A. The overall variable rate of $0.0147 per Dt was determined based on the current storage injection and withdrawal capacities of the Delaware Division's storage resources. This rate was cut in half to arrive at separate rates for injections and withdrawals. This is important because a transportation customer on any given day will either over deliver (the Company would inject the excess gas into storage) or under deliver (the Company would withdraw from storage to meet the demand) the customer-owned gas into the system on the customer's behalf. The resulting rate used for the variable gas supply component of the balancing services is $0.0147 per Dt.

Q. WERE THESE OVERALL FIXED GAS SUPPLY RESOURCE COSTS AND VARIABLE GAS SUPPLY RESOURCE COSTS UTILIZED IN THE DEVELOPMENT OF THE BALANCING SERVICE RATES?

A. Yes. The variable gas supply rate was used as the basis for the variable component in developing the balancing service rates. The fixed gas supply rate will differ between the balancing services due to the specific nature of the service being provided and the fact that the balancing rate is charged on consumption, not just the imbalance volumes. The fixed gas supply portion of the balancing service rates is based on specific load factors along with the percentage of the Company's gas supply needed to balance the requirements of specific customer class requirements. This percentage of the Company's gas supply will be the difference between their average day requirements and design day requirements.

Q. HOW WAS THE FIRM BALANCING SERVICE RATE FOR LARGE VOLUME SERVICE DEVELOPED?

A. Schedule J, Page 2 of 4 shows the development of the firm balancing service rate for this specific transportation customer class. The Delaware Division developed an average cost from the fixed rate of $120.4241 per Dt based on the Large Volume load factor of 28.03%. This load factor resulted in an average cost of $1.1806 per Dt. Since the Company's analysis determined that the DCQ method would provide approximately 54.75% of the peak day requirements, the Company would need to supply the remaining 45.25% with its gas supply resources. In other words, these firm customers would pay for only 45.25% of peak day requirements through the balancing service rate. The resulting rate for the fixed capacity based on this 45.25% would be approximately $0.5342 per Dt applicable to all consumption. The variable commodity rate of $0.0147 per Dt was multiplied by the estimated imbalance volume percentage of 24.91% to derive the variable rate of $0.0037 per Dt. The fixed capacity rate was added to the variable commodity rate to develop the final rate per Dt, which was then converted to a Mcf rate and Ccf rate as shown on Schedule J, page 2 of 4. The resulting balancing rate for the LVS rate schedule is $0.056 per Ccf.

Q. HOW WAS THE FIRM BALANCING SERVICE RATE FOR HIGH LOAD FACTOR SERVICE DEVELOPED?

A. Schedule J, Page 3 of 4 shows the development of the firm balancing service rate for this specific transportation customer class. The Delaware Division developed an average cost from the fixed rate of $120.4241 per Dt based on the High Load Factor Service load factor of 74.16%. This load factor resulted in an average cost of $0.4444 per Dt. Since the Company's analysis determined that the DCQ method would provide approximately 83.95% of the peak day requirements for this class, the Company would need to supply the remaining 16.05% with its gas supply resources which the transportation customers would pay for through the balancing service rate. The resulting rate for the fixed capacity based on this 16.05% would be approximately $0.0713 per Dt applicable to all consumption. The variable commodity rate of $0.0147 per Dt was multiplied by the estimated imbalance volume percentage of 3.42% to derive the variable rate of $0.0005 per Dt. The fixed capacity rate was added to the variable commodity rate to develop the final rate per Dt, which was then converted to a Mcf rate and Ccf rate as shown on Schedule J, page 3 of 4. The resulting balancing rate for the HLFS rate schedule is $0.007 per Ccf.

Q. WHAT ABOUT THE BALANCING RATE FOR INTERRUPTIBLE CUSTOMERS?

A. Schedule J, Page 4 of 4 shows the development of the balancing service rate for this specific transportation customer class. The Delaware Division developed an average cost from the fixed rate of $120.4241 per Dt based on the Interruptible Transportation Service load factor of 100%. This load factor resulted in an average cost of $0.3299 per Dt. The rate for the fixed capacity based on average cost at 6.58% would be approximately $0.0217 per Dt applicable to all consumption. The variable commodity rate of $0.0147 per Dt was multiplied by the estimated imbalance volume percentage of 6.58% to derive the variable rate of $0.0010 per Dt. The fixed capacity rate was added to the variable commodity rate to develop the final rate per Dt, which was then converted to a Mcf rate and Ccf rate as shown on Schedule J, page 4 of 4. The resulting balancing rate for the ITS rate schedule is $0.002 per Ccf.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

DATED: SEPTEMBER 4, 2009

STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF MICHAEL D. CASSEL

MICHAEL D. CASSEL, being first duly sworn according to law, on oath deposes and says that he is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of Michael D. Cassel;" that, if asked the questions which appear in the text of the direct testimony, he would give the answers that are therein set forth; and that he adopts this testimony as his sworn direct testimony in these proceedings.

Michael D. Cassel

Michael D. Cassel

Then personally appeared this 4th day of September 2009 the above-named Michael D. Cassel and acknowledged the foregoing Testimony to be her free act and deed. Before me,

REBECCA K. LITTLE
COM. EXP.
NOTARY
PUBLIC
8-7-2010
STATE OF DELAWARE

Rebecca K. Little

Notary Public
My Commission Expires: 8-7-2010

TESTIMONY OF MARIE KOZEL

BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF	)	
CHESAPEAKE UTILITIES CORPORATION	)	
FOR APPROVAL OF A CHANGE IN ITS	)	P.S.C. DOCKET NO. 09-
GAS SALES SERVICE RATES ("GSR")	)	
TO BE EFFECTIVE NOVEMBER 1, 2009	)	

DIRECT TESTIMONY OF MARIE E. KOZEL

On Behalf of Chesapeake Utilities Corporation

Delaware Division

Submitted for filing: September 4, 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Marie E. Kozel, and I am a Gas Supply II Analyst with Chesapeake Utilities Corporation ("Chesapeake" or "the Company"). My business address is 350 S. Queen Street, Dover, Delaware 19904.

Q. DESCRIBE BRIEFLY YOUR EDUCATION AND RELEVANT PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science Degree in Finance with a minor in English from La Salle University in Philadelphia, Pennsylvania. I have more than 15 years of progressively responsible experience in financial analysis. I was hired by Chesapeake Utilities Corporation in November 2007. My responsibilities are inclusive of all matters associated with gas supply and its procurement for Chesapeake Utilities Corporation. Immediately prior to joining Chesapeake, I was employed by ING Financial Services in West Chester, PA as Senior Financial Analyst in Operational Risk Management of the Retail Life Division, where I performed audits for the purposes of compliance with the Sarbanes Oxley Act of 2002. My responsibilities also included the implementation of operational risk management objectives, exposure analysis and awareness education for divisional staff. I have also held positions with

JP Morgan Chase and Radian Guaranty Inc., where I was responsible for revenue and expense analysis, budget preparation and staff management.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. No I have not. I have filed pre-filed testimony in prior Commission dockets.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my direct testimony in this Gas Sales Service Rate ("GSR") application is to provide support for the gas costs used in the calculation of the Delaware Division's three proposed Gas Sales Service Rates to be effective with service rendered on and after November 1, 2009. My direct testimony will also discuss the Company's gas supply and procurement activities as required by Commission Order No. 4767 issued on April 14, 1998 in the Company's Gas Sales Service Rate filing in Docket No. 97-294F.

Q. ARE THERE ANY SCHEDULES INCLUDED WITH YOUR DIRECT TESTIMONY?

A. No. In my testimony, I will be referencing two Schedules attached to the testimony of Jennifer A. Clausius. Schedule L is a summary of

Chesapeake's demand and capacity entitlements to be effective November 2009 and Schedule M is a chart of the Delaware Division's load and supply projections for the upcoming determination period.

Q. WHAT PIPELINE SUPPLIERS ARE CURRENTLY PROVIDING SERVICES TO THE DELAWARE DIVISION?

A. The Delaware Division is currently receiving a mix of transportation and storage services from four interstate pipeline suppliers. These four pipeline suppliers are Transcontinental Gas Pipe Line Company, LLC ("Transco"), Columbia Gas Transmission, LLC ("Columbia"), Columbia Gulf Transmission Company ("Columbia Gulf"), and Eastern Shore Natural Gas Company ("ESNG").

Q. WHAT WERE THE DELAWARE DIVISION'S CAPACITY ENTITLEMENTS ON UPSTREAM PIPELINES DURING THE LAST WINTER SEASON?

A. Schedule L represents the Delaware Division's winter season upstream capacity entitlements that were effective November 1, 2008.

Q. HAS THE DELAWARE DIVISION CHANGED ITS CAPACITY ENTITLEMENTS ON ANY OF THESE PIPELINES SINCE THE LAST GSR PROCEEDING?

A. Yes. The Delaware Division has obtained an additional 67 Dts of capacity on Transco as a result of a permanent capacity release from another Transco customer effective January 1, 2009. In addition, 7,500 Dts of capacity were obtained on Columbia, effective February 1, 2009. The Company also requested and anticipates an additional 7,500 Dts on Columbia that will take effect the later of November 15, 2009 or when the facilities are placed into service. As a result of the 2005 open season on ESNG, the Delaware Division increased its capacity entitlements by 4,000 Dts on the ESNG pipeline effective November 1, 2009. Schedule L shows the Delaware Division's capacity entitlements for the upcoming winter season that were used in the calculation of fixed demand costs for this determination period.

Q. PLEASE EXPLAIN THE CHANGE IN CAPACITY ENTITLEMENTS FOR THIS DETERMINATION PERIOD IN GREATER DETAIL.

A. For the past few years, due to steady growth in its residential and commercial customer base, the Delaware Division has experienced an increasing deficiency in capacity upstream of ESNG. Given the Company's unique location on the Delmarva Peninsula, supply is limited and comes at a premium. In an effort to reduce the deficiency of upstream capacity, the Company has sought a variety of different supply opportunities. Several pipelines have proposed projects to bring supply from the Rockies and/or the Marcellus Shale, but few have come to fruition. Late in 2008, Transco successfully put into operation Phase I of the Sentinel Project which gave the Delaware Division 10,000 Dts of upstream capacity from the Cove Point LNG facility. The additional 67 Dts of capacity obtained on Transco in 2009 was a result of the Company's ability to assume capacity no longer needed by another Transco customer. Columbia announced in January 2009, that additional capacity was available on its Line 1278 due to a change in operating mode. The Company requested and was awarded 7,500 Dts of capacity for a term of 10 years. The receipt point for this capacity is Wagoner Line K, located in Orange County, New York, where the Columbia line intersects with the Millennium Pipeline. This capacity gives the Company additional capacity upstream, as well as diversifying the Company's supply source. Columbia announced in March that additional facilities on its Line 1278 would be added with an anticipated in-service date of November 2009. The Company has requested and anticipates receiving an additional 7,500 Dts for a term of 2 years with the option for the Right of First Refusal. On ESNG, the Company increased its daily firm transportation entitlements under ESNG's FT Rate Schedule by 4,000 Dts effective November 1, 2009. This capacity is the last incremental increase that the Company committed to in ESNG's 2005-2008 expansion. In August of 2008, Transco offered to its customers who had Emergency Eminence Storage

Withdraw Service ("EESWS") the option to convert that storage to Eminence Storage Service ("ESS"). The Company had previously obtained EESWS in order to better serve its customers during hurricanes and times of supply disruptions. EESWS was a storage service that provided the Company the ability to withdraw and then replace the supply within 30 days. The Company felt that ESS storage would better serve its customers' needs and executed the option to convert effective April 1, 2009. The costs associated with these capacity increases have been appropriately included in the Delaware Division's GSR calculation for this determination period.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE COMPANY'S GAS SUPPLY PROCUREMENT ACTIVITIES SINCE NOVEMBER 1, 2008.

A. The Company has purchased a portion of its requirements from third party suppliers pursuant to short-term agreements and has used its Asset Manager for baseload and spot purchases to meet projected daily demand requirements. It is consistent with the Company's procurement practices to minimize its exposure to the volatility of the daily market during the winter season; therefore, most of the Company's gas supply costs during the winter months are based on fixed prices that are set prior to the beginning of the delivery month. The daily spot purchases referenced above are susceptible to the daily market volatility. However, due to the varying nature of the Company's demand requirements, it is essential to have an element of spot supply to insure the Company has the flexibility to comply with pipeline tariffs and operating requirements. During the period since November 2008, the Company procured firm supply to meet its demand requirements and maintain targeted storage inventory levels. A mix of pricing mechanisms, including commodity prices based on the published "Inside FERC" monthly index, the published "Gas Daily" midpoint and "triggers" based on New York Mercantile Exchange postings have been used to mitigate the impact of market fluctuations on the commodity cost of gas during this period. Effective July 12, 2007, the Company implemented the parameters identified in the commodity procurement plan ("plan") attached to the settlement agreement of PSC Docket. 06-287F. The parameters of the plan dictates that the Company will enter into physical transactions for natural gas for the upcoming twelve-month period on the second Wednesday of each month. The Company has followed the guidelines set forth in the plan since its implementation, with a modification made in consultation with the Commission Staff and Delaware Public Advocate ("DPA") in December 2008. The parameters of the plan also requires a review of the plan after two years, which will be one in conjunction with this application.

Q. PLEASE BRIEFLY EXPAIN THE RESULTS OF THE COMPANY'S NATURAL GAS PROCUREMENT PLAN SINCE NOVEMBER 1, 2008.

A. The Company's Natural Gas Commodity Procurement Plan will be discussed in a separate confidential compliance filing to be submitted with the annual hedging report.

Q. PLEASE BRIEFLY EXPLAIN THE COMPANY'S RELATIONSHIP WITH ITS ASSET MANAGER AND THE SERVICES THAT ARE PROVIDED.

A. In March 2009, the Company completed negotiations of a new agreement with its Asset Manager that resulted in a new three-year agreement. The Company's Asset Manager provides capacity management, as well as supply and dispatch scheduling on upstream pipelines, firm and interruptible gas supply, balancing of supply resources, and monthly accounting and reporting of transactions. The Company's firm customers benefit from the Agreement, which provides the Company with access to reliable and flexible supply alternatives in addition to enhanced fixed cost recovery relating to the Company's transportation and storage entitlements. The guaranteed cost recovery achieved by the Company is reflected as a credit on the monthly supply invoice that is submitted by the Asset Manager and the value that is generated pursuant to the Agreement is ultimately credited to the Delaware Division's firm customers through the Company's margin sharing mechanism. Under the new agreement, this credit increased $122,892 per year or 66% as outlined in the settlement of PSC Docket No. 07-186 and updated in the prior GSR settlement.

Q. WHAT ARE THE DELAWARE DIVISION'S PLANS REGARDING GAS SUPPLY FOR THE UPCOMING WINTER SEASON OF 2009-2010?

A. The Company has prepared demand projections for the upcoming winter season of 2009-2010, which is visually represented by Schedule M. It expects to meet those demand projections with supply purchases of baseload, daily spot, storage service and bundled gas. It is important to note that the Company's reliance on bundled gas will be significantly reduced during this determination period as a result of the increase in upstream capacity. Approximately 50% of the winter's expected requirements will have been procured utilizing the Company's Natural Gas Commodity Procurement Plan. The Company's agreement with its Asset Manager will mostly bridge the gap between the forecasted demand requirements and the supply and storage already procured. In addition, the Company will obtain the rights to call on natural gas supply in excess of its Transco and Columbia entitlements. This supply will be delivered on a firm basis to ensure the Company's ability to service its firm customers on a peak day. Chesapeake will continue to maintain "no requirements" contracts with several natural gas suppliers to ensure that alternative gas supply sources are readily available in the event they are needed. These contracts can provide firm gas supply upon the execution of confirmations by both parties.

Q. PLEASE PROVIDE INFORMATION ON CHESAPEAKE'S STORAGE SERVICE.

A. Chesapeake subscribes to several different storage services which provide flexibility during the winter season to meet customer needs. Currently, the Company manages three storages on ESNG and includes three storage services in the asset management agreement. The storages included in the asset management agreement are Eminence Storage Service ("ESS"), Washington Storage Service ("WSS") and Firm Storage Service ("FSS"). At the beginning of the asset management agreement, storage balances were reconciled and transferred to the control of the Asset Manager. In exchange for the transfer of gas inventory, the Asset Manager grants the Company the right to receive, on demand at the delivery point, the quantity of gas requested. The Company will designate quantities of gas to be injected or withdrawn. These quantities are understood to be paper transactions which may differ from the actual quantities held in storage at any point in time. This is because the Asset Manager has the right, subject to the Company's designation of storage and tariff limitations, to withdraw and inject as they see fit. On a monthly basis, the paper balance for each storage service under the Asset Manager is reconciled. Withdrawals from WSS are baseloaded monthly. Daily withdraws from FSS during the winter season are anticipated but not baseloaded. FSS is the Company's largest storage service and provides greater flexibility in scheduling with regards to changes in weather and unexpected fluctuations in demand. However, injections for FSS are baseloaded. The intent of ESS is to provide the Company a supply option during hurricanes or supply disruptions. Since the Company views the main purpose of ESS is to mitigate supply disruptions during the hurricane season, it is the Company's plan to fill ESS by August 1 each year. The three ESNG storage services are General Storage Service ("GSS"), Leidy Storage Service ("LSS"), and Liquefied Natural Gas Storage Service ("LGA"). The Company is not able to baseload withdrawals or injections for these storage services. GSS is a year round storage service and provides the Company swing capability throughout the year. LSS and LGA are seasonal storage services, meaning that injections can only be made April through October and withdrawals are available November through March. LGA is a higher priced storage service and capacity is limited. Therefore, LGA is designed for use on peak days. The Company tracks the storage levels of each storage service closely, in order to comply with limitations set by each storage service Tariff.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?
A. Yes, it does.

DATED: SEPTEMBER 4, 2009

STATE OF DELAWARE)
)
COUNTY OF KENT)

AFFIDAVIT OF MARIE E. KOZEL

MARIE E. KOZEL, being first duly sworn according to law, on oath deposes and says that she is the witness whose testimony appears as "Chesapeake Utilities Corporation, Delaware Division, Direct Testimony of Marie E. Kozel;" that, if asked the questions which appear in the text of the direct testimony, she would give the answers that are therein set forth; and that she adopts this testimony as her sworn direct testimony in these proceedings.

Marie E. Kozel

Marie E. Kozel

Then personally appeared this 4th day of September 2009 the above-named Marie E. Kozel and acknowledged the foregoing Testimony to be her free act and deed. Before me,

REBECCA K. LITTLE
COM. EXP. 8-7-2010
NOTARY PUBLIC
STATE OF DELAWARE

Rebecca K. Little

Notary Public
My Commission Expires: 8-7-2010